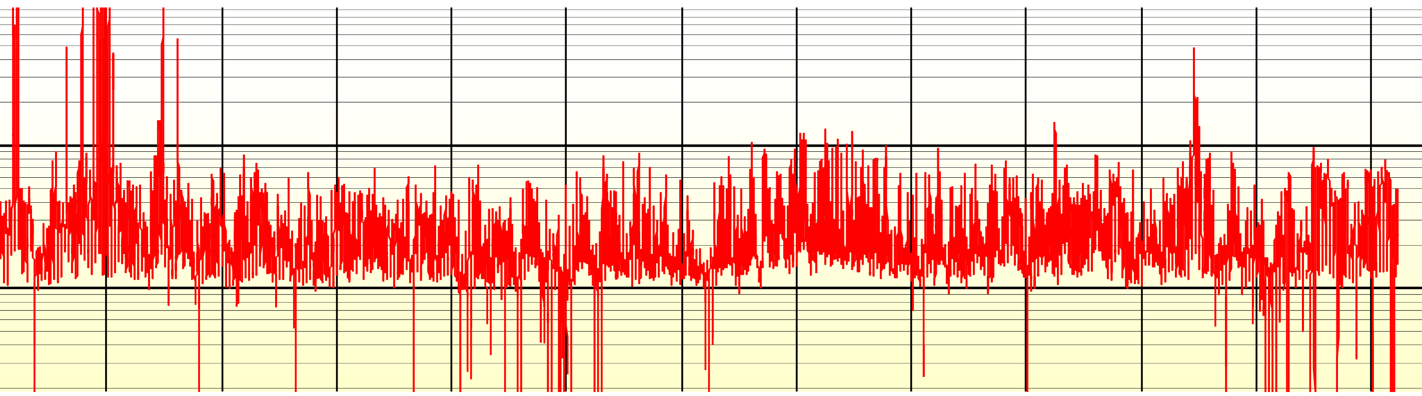
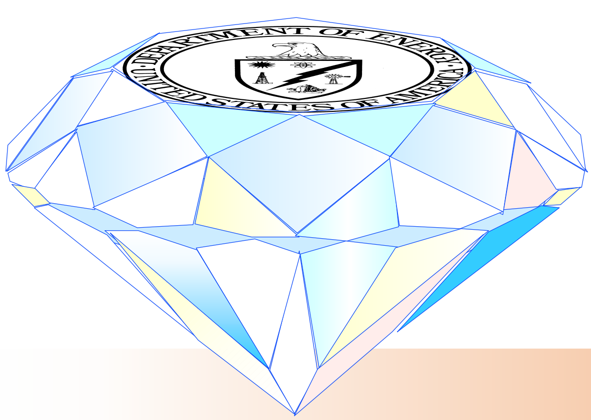
Report No. EJ-2002-05
September 2002

2002 Characterization of the PJM Region



DOE GEM-SET



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National Energy Technology Laboratory

Report No. **EJ-2002-05**
DOE Contract Number DE-AM26-99FT40465 / Task 50901: Market and Environmental Analysis
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Final Report

GEMSET Regional Segmentation Analysis:

2002 Characterization of the PJM Region

September 2002

Prepared for:
The United States Department of Energy
National Energy Technology Laboratory

DOE Project Manager:
Patricia A. Rawls

Prepared by:

PARSONS

1 Meridian Boulevard, Wyomissing, Pennsylvania 19610-3200 USA

Principal Investigator:
Christopher Wiederspahn

Task Manager:
Richard E. Weinstein, P.E.

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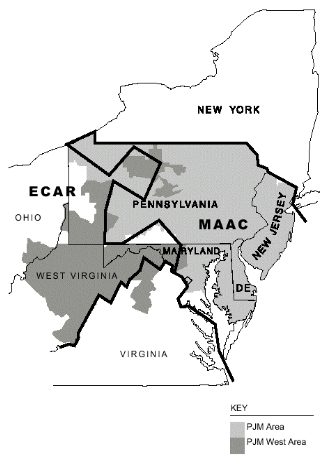
Technical Report Abstract

EJ-2002-05

2002 Characterization of the PJM Region

PJM Interconnection, LLC (PJM) operates the largest competitive wholesale market in the world as well as North America's largest power grid. It controls delivery of more generation than any other centrally dispatched electrical system, having recently eclipsed that of both the Tokyo Electric Company and the country of France. Established in 1927, PJM was the country's first fully functioning regional transmission organization, and today controls 71,639 MW of generation, serving a load that peaked on August 14, 2002 at approximately 64,127 MW in the combined PJM East and PJM West regions.



To understand PJM is to understand the current direction for the overall design of the future North American electrical system. PJM's administration and operations are considered by many to be a model for other regions contemplating bid-based electric market operations. PJM has institutionalized means for all participants in deregulated markets to fairly and equally participate, and to manage the changing conditions inevita-ble during the industry's restructuring. As proof of this, delegates from more than 70 nations have been sent to PJM to learn about the market model and the operation of its electrical grid.

Source: Maryland Power Plant Research Project

This report describes how PJM operates now, its various markets, and the current revenue potential for generators in the region. It reviews historical prices, expected load growth, and generation currently in queue. It draws heavily upon public data and documents found on PJM's website, and those of the MISO-PJM-SPP initiative, MAAC, NERC, and FERC, as well as other public and private sources. These are listed at the end of this document and footnoted where taken in their entirety. This report is one of a series describing the market conditions that exist, and that are part of the forecast of the Department of Energy's (DOE) Government Energy Market Segment Evaluation Tool (GEMSET) project. GEMSET forecasts for PJM and other areas will be presented in future reports in the series, where the GEMSET evaluation team makes reasoned conjecture of what might occur in these electric power markets in the future under a range of possible future energy price and economic circumstances. Other reports in this GEMSET series then analyze these PJM forecasts, and assess them in the context of several future scenarios of factors influencing demand, generation mix, and price. The discussions in this report are arranged in six sections:

CONTACT POINT

Patricia A. Rawls
Project Manager
Office of System and Policy Support
(412) 386-5882
Fax: (412) 386-6195
rawls@netl.doe.gov

National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236-0940

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507-0880

GEMSET WEB SITE

www2.epix.net/~parsons
select GEMSET

Task Manager:

Richard E. Weinstein
(484) 338-2293
richard.e.weinstein@parsons.com

Parsons
1 Meridian Boulevard – Suite 2B-1
Wyomissing, PA 19610-3200
Fax: (484) 338-2354

Report No. EJ-2002-05
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GEMSET Regional Segmentation Analysis: 2002 Characterization of the PJM Region

Study Region
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- Section 1 describes the PJM region, responsibilities, generation mix, and timeline of significant events in PJM history.
- Section 2 describes the rules for operating and adding generation in PJM.
- Section 3 describes PJM's markets, and reviews recent historical electricity prices and trends.
- Section 4 gives PJM's forecasts of demand growth, and projections of generating capacity.
- Section 5 frames the current revenue stream opportunities for generators in the region.
- Section 6 looks at the changing geography and role of PJM, and its longer-term implications for generation costs and capacity availability, as well as critical business impacts that will determine electric pricing in the future.

Table of Contents

These data are dynamic, and those reported here represent a "snapshot" of information available just prior to this report's issue date, September 2002. Periodically, the PJM region will be revisited, and this report revised.

The reader should check with the DOE project manager, Patricia A. Rawls, to see if there is a more recent issue of this report, or to discuss any related information that might be available about the region, or about the GEMSET project data.

Ms. Patricia A. Rawls
Project Manager, Office of System & Policy Support

U.S. Department of Energy
National Energy Technology Laboratory
Mail Stop 920-L
P.O. Box 10940
Pittsburgh, PA 15236-0940
Phone: (412) 386-5882
Fax: (412) 386-4818
e-mail: Rawls@NETL.DOE.GOV

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List of Exhibits

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Patricia A. Rawls, *Project Manager*

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Charles J. Drummond
Thomas J. Hand

This report was prepared by the following **Parsons** personnel:

Task Manager:
Richard E. Weinstein, P.E.
Project Support:
John L. Haslbeck
Nancy S. Lewis

Principal Investigator:
Christopher Wiederspahn
Lead Economist:
Albert A. Herman, Jr.

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Abbreviations and Acronyms

Term	Meaning
AAGC	average automatic generation control
ACAP	available capacity (as in PJM West)
AEO1999	EIA Annual Energy Outlook 1999
AEO2000	EIA Annual Energy Outlook 2000
AEO2001	EIA Annual Energy Outlook 2001
AEO2002	EIA Annual Energy Outlook 2002
AEP	American Electric Power
AGC	automatic generation control
ALM	Active Load Management
ASCC	Alaska Systems Coordinating Council
AVR	automatic voltage regulator
Bcf	billion cubic feet, that is, 10^9 cubic feet
BME	balancing market evaluation
CAISO	California Independent System Operator
Capacity Resource	Generator qualifying as PJM capacity
CARL DATA	control area resource and load data submitted by Control Area Resources to the ISO
CDR	Capacity Deficiency Rate
COE	the cost of electricity, the levelized busbar cost of electric production including amortized capital, operating, and maintenance costs
combustion turbine, CT	a synonym for gas turbine, used interchangeably
ComEd	Commonwealth Edison
CP&L	a Progress Energy company
DAM	day-ahead market
DCA	Department of Community Affairs
DEP	Department of Environmental Protection
DMNC	dependable maximum net capability
DNI	desired net interchange
DOE	United States Department of Energy
DSM	demand side management
ECAR	East Central Area Reliability Coordination Agreement, a NERC region

EDC .... Electric Distribution Company
EFORd .... demand equivalent forced outage rate
eGADS.. electronic generating availability data system; an electronic data system allowing the posting of data regarding a generating unit's availability record
EIA .... the Energy Information Administration of the DOE
EPA .... U.S. Environmental Protection Agency
EPAct .... Energy Policy Act of 1992
EPRI... Electric Power Research Institute
ERCOT .... Electric Reliability Council of Texas, a NERC region
ERO.. industry self-regulatory electric reliability organization
EUE .... expected unserved energy
FERC.. Federal Energy Regulatory Commission
FGD .... flue gas desulfurization, a sulfur emission control device
FGT .... Florida Gas Transmission, a natural gas transportation pipeline company
FLOASIS .... Peninsular Florida's OASIS
FPC.. Florida Power, a Progress Energy company
FPL .... Florida Power & Light Company
FPSC .... Florida Public Service Commission
FRCC .... Florida Reliability Coordinating Council, a NERC region
FTR .... Financial Transmission Right
GADS .... generating availability data system; see "eGADS"
gas turbine, GT......................... a synonym for combustion turbine, used interchangeably
GEMSET .... government energy market segment evaluation tool
GNP .... gross national product
GT.. gas turbine (a synonym for combustion turbine)
GTCC.. natural gas fueled gas turbine combined cycle
HAM.. hour-ahead market
HHV .... higher heating value of a fuel including the heat released if all of the water vapor in the combustion products were condensed
HRSG.. heat recovery steam generator
ICAP.. installed capacity requirement
IOU.. investor-owned utility
IPD.. implicit price deflator
IPM.. the EPA's integrated planning model
IPP .... an independent power producer, an unregulated electric generating company
IRM .... installed reserve margin

IRP .... integrated resource plan

ISO .... independent system operator; a regulated body that dispatches all competitive electric generation on the high voltage transmission grid within its service region; they operate the grid, administer the power pools power transfers, select the lower cost generation bid into the pool according to the pool's operating rules, and maintain the integrity of the electric transmission grid

ISONE...................................... New England ISO

ITC .... Independent Transmission Company

JEA .... Jacksonville Electric Authority

KUA .... Kissimmee Utility Authority

LAK .... City of Lakeland

LBMP .... locational-based marginal pricing

LCC.. local control center

LHV .... lower heating value of a fuel, the heat released if all of the water vapor in the combustion products remained as steam

LMP .... locational marginal price

LOC .... lost opportunity cost

LOLE.. loss of load expectation

LOLP .... loss of load probability

LSE .... load-serving entity

MAAC...................................... Mid-Atlantic Area Council, a reliability council, a NERC region

MAIN....................................... Mid-America Interconnected Network, a NERC region

MAPP .... Mid-Continent Area Power Pool, a NERC region

MCP... market clearing price

MCR .... maximum continuous rating

MISO .... Midwest Independent System Operator

MMU.. Market Monitoring Unit

MOU .... Memorandum of Understanding

MVA .... megavolt amperes

MVAR...................................... megavolt-ampere-reactive

MWe .... electrical megawatts

MWth....................................... thermal megawatts

NAERO.................................... the North American Electric Reliability Organization; NERC is in the process of transforming itself into NAERO, whose principal mission will be to develop, implement, and enforce standards for a reliable North American bulk electric system. (NERC has no enforcement capability.)

NEL.. net energy for load

NEMS .... the EIA's national energy modeling system

NERC .... North American Electric Reliability Council; soon, NERC, without enforcement authority, will become NAERO with that authority

NERTO .... North East Regional Transmission Owner

NETL... the U.S. Department of Energy's National Energy Technology Laboratory

NOPR .... notice of proposed rulemaking

NOx .... nitrogen oxides, types of air pollutant, mainly NO and NO_2

NPCC .... Northeast Power Coordinating Council, a NERC region

NUG.. non-utility generator, a competitive, unregulated independent electric power producer

NYCA .... New York Control Area

NYISO...................................... the New York State independent system operator, a NERC region

NYMEX .... New York Mercantile Exchange

NYPA .... New York Power Authority

NYPP.. New York Power Pool

NYSRC..................................... New York State Reliability Council

O&M .... operation and maintenance

OASIS .... open-access same-time information system

OATT .... open access transmission tariff

OI.. PJM Office of the Interconnection, LLC

OTAG.. Ozone Transport Assessment Group

OTR.. Northeast Ozone Transport Region

OUC.. Orlando Utilities Commission

P.E. .... licensed professional engineer

PCD .... particulate emission control device

PECO .... Philadelphia Electric Company

PJM .... Pennsylvania, New Jersey, Maryland, or PJM Interconnection LLC, an ISO/RTO

PPL... Pennsylvania Power & Light Company

PRL .... price responsive load

PSC... local state Public Service Commission

PSE&G...................................... Public Service Electric & Gas Company

PUHCA .... Public Utilities Holding Company Act

PURPA...................................... Public Utility Regulatory Policy Act of 1978

RACT .... reasonably available control technology (pollution control)

RAG.. Reliability Assessment Group

RMCP .... regulation market clearing price

RTEM .... real-time energy marketplace

RTO.. regional transmission operator

RWG .... Resource Working Group
SAS .... Statement on Auditing Standards
SCD .... security-constrained dispatch
SCNG .... Strategic Center for Natural Gas
SCUC .... security-constrained utility commitment
SERC .... Southeast Electric Reliability Council, a NERC region
SMCP .... spinning market clearing price
SMD .... FERC's Standard Market Design for competitive electric markets
SOx .... sulfur oxides, types of air pollutant, mainly SO_2
SPP .... Southwest Power Pool, a NERC region
SRE .... supplemental resources evaluation
State Estimator .... PJM system model
SWG .... Stability Working Group
TCC .... Transmission Congestion Contracts
TECO .... Tampa Electric Company
TWG .... Transmission Working Group
TYSP .... 10-year site plan
UDI .... Utility Data Institute
VAR .... volt-ampere-reactive
WECC .... Western Electricity Coordinating Council (formerly WSCC), a NERC region

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1. PJM Interconnection, LLC

1.1 History

PJM was formed in 1927 in order to share the resources of three utilities, Philadelphia Electric Co. (PECO), Pennsylvania Power & Light Co. (PP&L), and Public Service Electric & Gas Co. (PSE&G), thus allowing them to increase efficiencies. This became the world's first power pool. PJM became the first fully functioning Independent System Operator (ISO) in 1998, responsible for both the safety and reliability of the transmission system and overseeing the administration of a competitive wholesale electric power market.

PJM dispatches the generation of 614 generation sources serving most of Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia, and, with the addition of PJM West in April 2002, parts of Virginia, West Virginia, and Ohio. The scope of the PJM East and PJM West operations includes:

- 25.1 million people served
- 64,127 MW (megawatts) of peak load
- 71,639 MW of generation capacity
- 298,011 GWh (gigawatt hours) of energy per year
- 614 generation sources of diverse types
- 13,100 miles of transmission lines
- 200 members
- $9 billion in energy and energy service trades since 1997

PJM is a limited liability company that operates on a profit neutral basis. PJM's Operating Agreement and Tariff provide that it can recoup its operating expenses from its member companies. Debt service is included in the operating expenses that PJM bills to members on a monthly basis. It is a non-stock corporation owned by its members and governed by the Federal Energy Regulatory Commission (FERC) in cooperation with the state regulatory boards in which it operates. Other income comes from studies and interconnection fees, membership dues, and interest.

Today, PJM has evolved to become more of a process than a specific region, though its physical region is expanding rapidly as well. The recent debacles in wholesale trading and stalled unregulated retail initiatives, most notably in California, have demonstrated the need to provide a uniform set of operating principles that will allow the forces of supply and demand to work freely in a transparent manner while encouraging participation by new, non-utility participants. PJM has shown it has the technology (notably a suite of Internet scheduling and trading tools) and organizational structure to accomplish this while maintaining system reliability. PJM's operating territory as of August 2002 is shown in Exhibit 1-1.

Exhibit 1-1
The PJM Operating Territory

PJM's organization is in Exhibit 1-2. It is a two-tiered governance model intended to ensure independent decisions based on a consensus of stakeholders. PJM's Members Committee, advisory committees, user groups, and PJM staff all contribute advice in support of one another. The Member Committee is a voting body comprised of PJM members and five voting sectors. Each sector is given the same voting weight despite the varying numbers of members that belong to each. Only one affiliate of any corporate entity member may vote in the Members Committee. Exhibit 1-3 is a timeline of some of PJM's more significant events.

Exhibit 1-2
PJM Organization

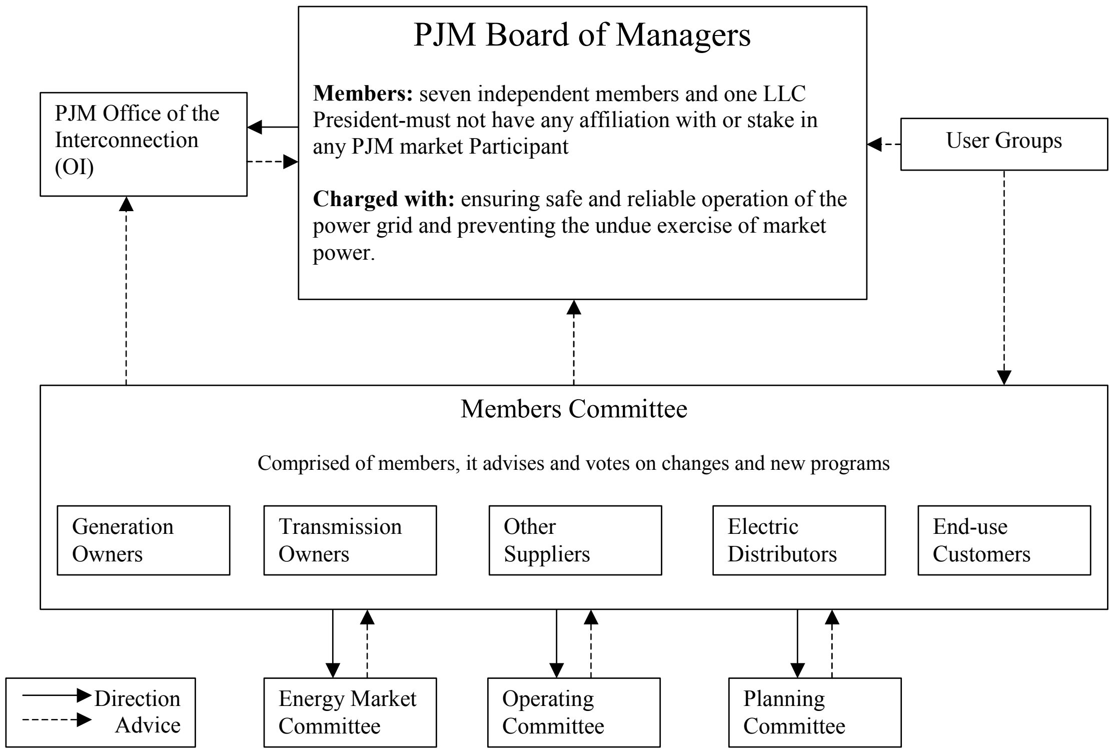


Exhibit 1-3
Timeline of Significant PJM Events

Year	Event
1927	PJM Founded
1935	PUHCA
1956	PJM Agreement
1965-7	Northeast Blackouts
1968	NERC Established
1970	Valley Forge Control Center opens
1978	PURPA
1992	Energy Policy Act of 1992
1996	FERC Order No. 888, PJM.COM established
1997	ISO NE, eSchedule, OASIS, Spot Market Operations and LLC established
1998	eData, eCapacity credits market, EGADs (generating unit information), FERC approves PJM ISO
1999	eEEs-Submit energy schedules, eDWT transmission outage information, eFTR-FTR auction established
2000	FERC Order No. 2000, eMkt - Day Ahead Market, eMkt - Regulation Market established
2001	California Electricity Crisis
2002	PJM West established, Enron Collapse, MISO-PJM-SPP, PJM South agreement, FERC Standard Market Design unveiled

More recent PJM events of note include:

- March 2001 – New England ISO (ISONE) purchased SMD software based on PJM's model.
- March 2001 – Orange & Rockland Electric in New Jersey joined PJM.
- July 2001 – FERC granted PJM provisional Regional Transmission Operator (RTO) status.
- March 2002 – FERC announces its intention to reform Open Access Transmission Tariffs to promote a standardized wholesale electric market design.
- April 2002 – The Allegheny Energy transmission system was integrated into PJM. For the first time nationally, two separate electrical transmission systems operate under a single energy market and a single governance structure across multiple North American Electric Reliability Councils.
- May 2002 – Dominion (Virginia Power) announced plans to establish PJM South, similar in operation to that of PJM West, and would allow Dominion's 6,000 miles of transmission lines in Virginia and North Carolina to be operated separately under a single combined energy market.
- May 2002 – MISO, PJM, SPP, and TRANSLink sign Memorandum of Cooperation.
- June 2002 – American Electric Power (AEP), Commonwealth Edison (ComEd) and Illinois Power execute an agreement to form an independent transmission company managed by National Grid that would operate within PJM West.
- June 2002 – PJM signed a Memorandum of Understanding (MOU) with NYISO to hold open discussions about integration between the regions.
- July 2002 – Dayton Power & Light announced its intent to join PJM West.

1.2 PJM Roles and Responsibilities

PJM is its region's Regional Transmission Operator (RTO) with responsibility to act in several roles, including:

- Control Area Operator

- Transmission Provider
- Market Administrator
- Regional Transmission Planner
- NERC Security Coordinator

PJM is responsible for the region's electric integrity, unit dispatch and reliability, and administering the pricing mechanisms for delivery of all power. With the implementation of the PJM Open Access Transmission Tariff in 1997, PJM began operating the nation's first regional bid-based energy market, and now operates six competitive markets selling energy, capacity and ancillary services. PJM enables participants to buy and sell energy, schedule bilateral electric sale transactions, and reserve transmission service. PJM provides the accounting and billing services for these transactions.

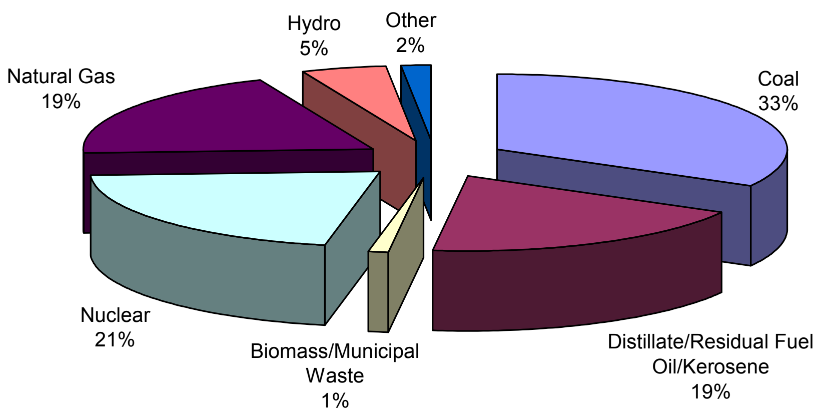
Each day, PJM forecasts how much electricity will be needed and receives offers to supply electricity from producers and other suppliers of electricity. PJM decides what offers to accept by selecting which plants will make electricity over the next period. PJM bases its decisions on the overall least cost for the whole region, considering the pattern of demand and availability of supply. PJM directs the operation of the generation plants by agreements with their owners. The electricity actually flows through transmission lines (high tower, high voltage lines) to local utilities' distribution station and from there is sent on local electric lines to homes, factories and businesses. PJM also anticipates electricity needs years ahead and makes plans to ensure that enough electricity will be there as the region grows.[1]

1.3 Generation Mix

Due to a combination of new generation units coming online and the addition of PJM West in April 2002, the installed capacity of PJM (East and West) increased by 12,902 MW from January of 2001 to June of 2002. Generation capacity in PJM East is currently 62,563 MW based on the GEMSET stacking order compiled on August 28, 2002. As of August 2002, PJM estimates that it dispatches 71,600 MW of generation in PJM East and West combined. The mix of fuels in PJM East as indicated in the stacking order is shown in Exhibit 1-4.

[1] *PJM – The Power of Connecting*

Exhibit 1-4
PJM Installed Capacity by Fuel Type



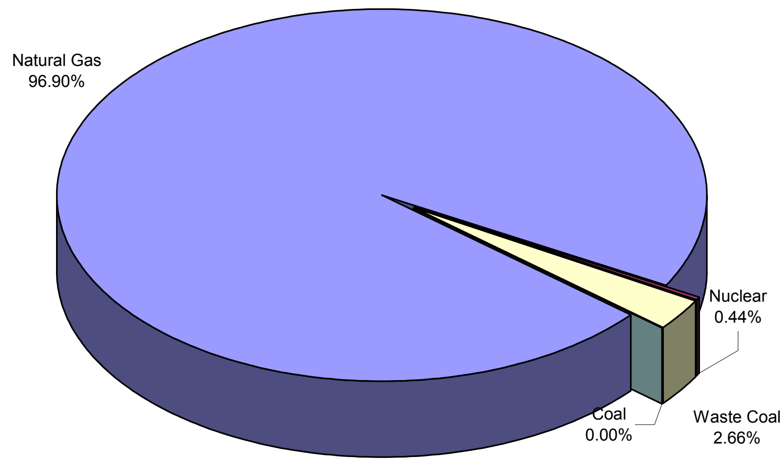
Source: GEMSET PJM Generation Stack 8-28-02

1.4 Baseload

Exhibit 1-4 reveals that some 53%, or roughly 31,000 MW, of current PJM East generating capacity was fueled by coal or nuclear power as of December 31, 2000. During 2000, 60% of the hours were below the total generation of these two types of baseload generation. During the year ended June 30, 2002, that number had slipped to 42%.

Short-term planned capacity additions are referred to in this report as "planned generation," and include plants already in some phase of construction. Based upon PJM's response to the NERC Data Request for 2002 (formerly MAAC Form 411), this generation capacity in PJM East sums to 11,439 MW by the end of 2004. The vast majority of this planned generation is to be fueled by natural gas as shown in the graph below. A review of the PJM generation queue, which lists requests for feasibility, impact and facilities studies (and always shows a much higher number of projects than planned generation figures), also indicates that no new coal- or nuclear-fueled baseload units are currently past the impact study stage.

Exhibit 1-5
PJM East Planned Generation – Fuel Type

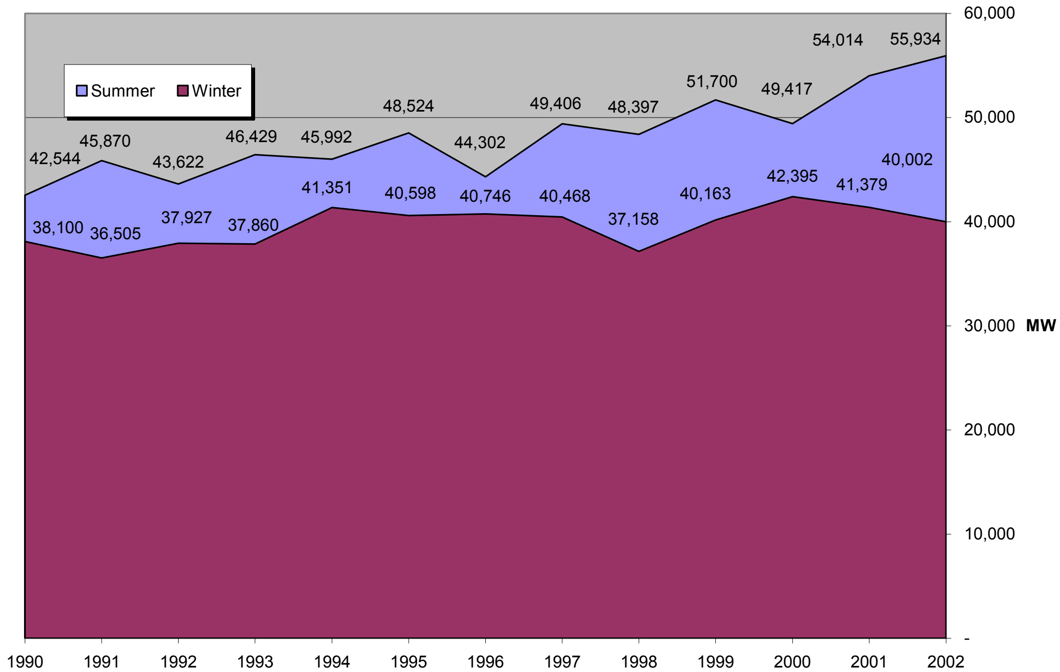


1.5 Peak Demand

In 1999, 500 hours exceeded the 80% level of the peak hour on the system and reached approximately 10,000 MW of peak load. In the year ended June 30, 2002, there were only 288 such hours, representing a peak of approximately 10,500 MW above the 80% mark. PJM has sufficient peaking capability in gas turbines, diesels, and hydro to cover this amount of peak demand over the next several years.

The 2001 PJM peak load was 54,014 MW, set on August 9 at 3 p.m. That record will be broken in 2002, with the preliminary data showing that, on August 14 at 4 p.m., PJM East peaked at a record high of 55,934 MW, or a total of 64,127 MW system-wide when combined with the PJM West load of 8,193 MW. Exhibit 1-6 illustrates historical peak loads for PJM East in both summer and winter periods since 1990.

Exhibit 1-6
PJM System Peaks 1990-2002

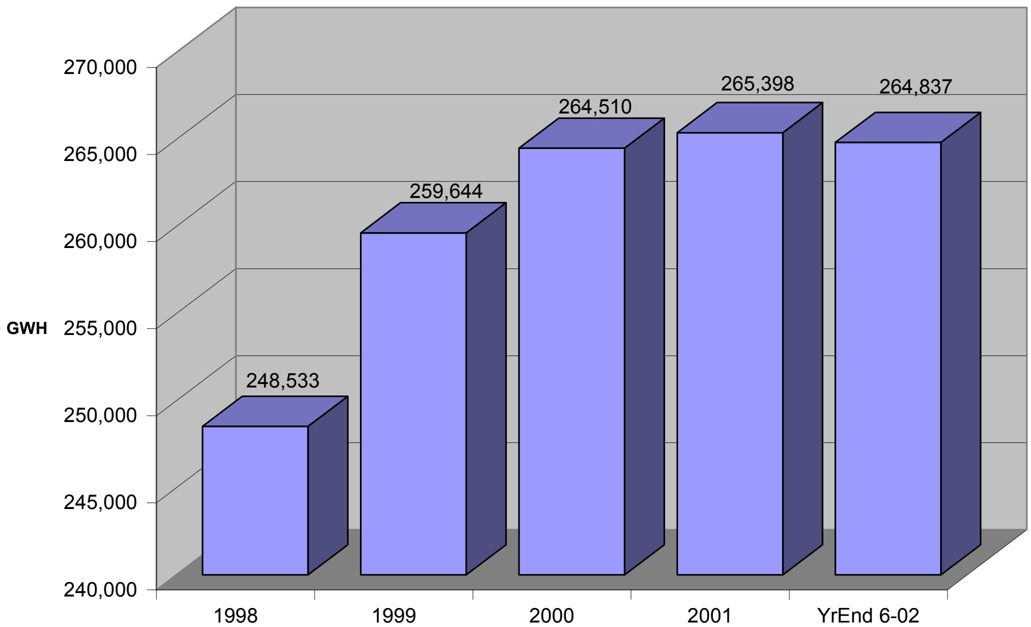


Note: 2002 Peak Data preliminary

1.6 Energy Consumption

The 2001 net energy for load in PJM East was 265,398 GWh, a modest increase of 0.34% from the total for 2000. The total net energy load for the year ending June 30, 2002 was 264,837 GWh, or a 0.21% reduction from that of the full prior year, owing in part to the mild winter of 2001-02. Exhibit 1-7 represents energy consumption for 1998 through the year ending June 30, 2002.

Exhibit 1-7
PJM East Net Energy 1998-2002



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2. GENERATION IN PJM

This section discusses the issues pertaining to building and operating generating units in PJM.

2.1 Performance Data and Unforced Capacity Accounting

Generators that serve as Capacity Resources must initially submit design data in hard copy followed by monthly electronic data regarding its performance to the generating availability data system (eGADS). PJM eGADS, an Internet application, allows generators to submit and view outage data. Every month PJM uses the most recently available 12-month history of eGADS data to calculate the demand equivalent forced outage rate (EFORd) for each generating unit. This measure of unit availability is used to convert the installed capacity rating of the unit to an unforced capacity rating for use in the PJM capacity markets for the next month. The unforced capacity rating of a unit is defined as the installed capacity multiplied by (1-EFORd). For example, a unit with an installed capacity rating of 100 MW and an EFORd of 10% would have (1-EFORd) equal to 0.9, resulting in an unforced rating of 100 MW multiplied by 0.9, or 90 MW. In addition to the initially submitted design (pedigree) data, all generator owners must submit the following monthly performance and event data into PJM eGADS[2] by the 20th of the following month:

- **Outage Event Data** – Record of times and causes for a unit being out of service.
- **Generation Performance Data** – Monthly generation, service hours, fuel consumption.

[2] *Additional specification on submitting each type of data can be found in the PJM eGADS User Manual on the PJM website at www.pjm.com*

2.2 Generator Testing

Generating units designated as Capacity Resources in PJM must be tested on a routine basis to verify their performance. Summer rating tests are conducted during June, July, or August, and winter tests are conducted in December, January, or February. Tests must be conducted based on PJM guidelines, with reports submitted to PJM in September and March. Details for these PJM generation member requirements can be found in the Manual on Rules and Procedures for Determination of Generating Capability posted on the PJM website, www.pjm.com.

2.3 Coordination of Operation

Real-time coordination of operations between PJM and the generation facility is essential for maximum efficiency. Every generator that is interconnected with and synchronized to the transmission system must coordinate its operation with PJM and provide all necessary and requested information and equipment status to assure that the electrical system can be operated in a safe and reliable manner. This coordination encompasses, but is not limited to:

- Supplying PJM requested generator net MW and MVAR output.
- Supplying frequency and voltage levels.
- Scheduling the operation and planned outages of facilities including synchronization and disconnection.
- Alerting PJM of impending forced outage situations where possible.
- Providing data required for operations and system studies.
- Notifying PJM of any condition that inhibits its operating in a reliable manner.
- Providing documented startup and shutdown procedures including ramp-up and ramp-down.
- Following PJM-directed plant operation during grid emergency and restoration conditions.
- Following PJM-directed operation during transmission-constrained conditions.

The generator owner must develop operating principles and procedures for its facility, coordinated with PJM requirements. The owner must also provide the necessary training and certification for appropriate operations staff employees, and provide facilities for necessary communication with PJM.

2.4 Generator Operations Under Emergency Operating Conditions

While the smooth running of PJM under normal circumstances is an important technical and economic function, the stable operation of the grid under abnormal circumstances and during emergencies is one of the most critical elements and responsibilities of PJM operations. In order to maintain system reliability during emergency operations, it is critical that generators respond to directives from PJM. During an emergency, as determined/declared by the Local Reliability Center or PJM, PJM requires that each generator respond as promptly as possible to all directives from the Local Reliability Center and PJM with respect to all matters affecting the operation of the facility including, without limitation, the following:

- Thermal overload of electrical circuits (actual or contingency), and/or
- High- or low-voltage conditions (actual or contingency).

The Local Reliability Center may also direct the generator to:

- Adjust (increase or decrease) the facility energy and/or reactive output, and/or
- Connect or disconnect the facility from the PJM electrical system and/or deviate from the prescribed voltage or reactive schedules.

During emergencies, the generator and PJM maintain communications and contact during all PJM or Local Reliability Center's emergency operations. When the Local Reliability Center has determined that the emergency conditions have been alleviated, the facility will be allowed to return to normal operations consistent with good operational practice. In order to safely restore the transmission system following a facility outage, the facility isolated from the PJM electrical system must reconnect only under the direction of the Local Reliability Center.

2.5 Operator Training

Training of operators is essential to promote reliable operations. Formal training programs are available and are periodically offered to generator personnel including dispatchers, generator operators, and others who control generator output and/or transmission assets.

Training includes but is not limited to PJM System Operator Procedures, PJM Emergency Operating Procedures, data reporting requirements, and switching and related transmission issues. The North American Electric Reliability Council (NERC) has developed a system operator certification program. In the future, PJM may require a generator owner to employ certified system operators if they wish to participate in PJM. PJM intends to offer both core and optional courses for generator personnel to further ensure reliable system operations. Additional details regarding PJM System Operations can be found in the PJM Manual on Dispatching Operations posted on the PJM website, www.pjm.com.

2.6 Interconnecting

PJM is connected on all sides by other power pools that vary in their roles and the rules by which they operate. PJM is responsible to ensure that power moves from these outside generating resources to the demand centers within PJM in the most economical way possible in PJM East and West. The planned additions of MISO, SPP, and Dominion Virginia Power as PJM South will greatly enhance the diversity of both load and generation in the region. This will create a much greater ability to move more resources in order to serve changing loads as they manifest themselves over a larger area. Instead of independent operation of several smaller control areas, consolidation will allow generation resources to be modeled and dispatched under a single coordinating body, with resources optimized based on market signals for demand and supply.

2.7 Adding New Generation Capacity in PJM

This section discusses the PJM approval hurdles needed by any generating company owner planning to add any interconnected generation in the region, whether committed as an energy-only or Capacity Resource.

2.7.1 Interconnection Request

New and/or existing generating units that will have changes to their output capability are required to submit an interconnection request, executed feasibility study agreement, and $10,000 non-refundable deposit (to be credited toward required study costs). These projects will be placed into a queue and will be evaluated under the same study procedure as new generation.

New generation applicants may request either of two forms of interconnection service, capacity or energy-only service. Energy-only status allows the generator to participate in energy markets based on locational prices. Capacity status is based on providing sufficient transmission capability to ensure deliverability to network load within PJM and to satisfy various contingency criteria established by the Mid-Atlantic Area Council (MAAC). Specific tests performed during the feasibility and system impact studies identify upgrades required to satisfy these criteria.

Change of Ownership: New owners of existing generators in PJM need to review proposed business practices with PJM and execute an interconnection service agreement with PJM. These units are not subject to the process for studying the impact of new generation unless pre-existing capacity injection rights for the unit are not transferred with the change of ownership.

2.7.2 Feasibility Study

The feasibility study is an analysis procedure used by PJM to assess the practicality and costs involved to incorporate a generating unit into PJM. The analysis is limited to load flow analysis of the more probable contingencies and short circuit studies and does not include grid stability. The study focuses on determining preliminary estimates of type, scope, cost, and lead time for construction of transmission facilities required to interconnect the project. Results are provided to the applicant and the affected transmission owners and are published on the PJM web site. PJM maintains the confidentiality of the applicant in these reports. After reviewing the results of the feasibility study, the applicant decides whether or not to pursue the system impact study. If the applicant decides to proceed, a system impact study agreement must be submitted to PJM with a $50,000 deposit. Proof is required of initial application for required air permits, if any, and the applicant must identify whether the project is to be connected as a capacity or energy-only resource.

2.7.3 System Impact Study

The system impact study is a comprehensive analysis of the impact of adding the new generation to the Interconnection, and its deliverability to PJM load. The study identifies the system constraints relating to the project and the attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades. Relationships are studied between the new generator, other planned new generators in the queues, and the existing Interconnection as a whole. This study also encompasses an analysis of existing firm and non-firm transmission service requests. The results of the study will be provided to all applicants who had projects evaluated in the study project, and to affected transmission owners, and will be posted on the PJM web site. While confidentiality obligations are honored by PJM, the identity of the applicants at this stage is not considered confidential in these reports. The identity of all applicants, and the size and location of projects for which system impact studies have been completed are published on the PJM web site. After reviewing the results of the study, the applicant must make a decision on whether or not to continue with the project.

2.7.4 Facilities Study

Upon completion of the system impact study, PJM furnishes a facilities study agreement to the applicant. The facilities study agreement provides the estimated cost responsibility and estimated completion date for the study. It may also define milestone dates that the proposed project must meet to retain its assigned priority. If the applicant decides to proceed, the executed facilities study agreement is returned to PJM accompanied by the required deposit. The deposit at this stage will be either $100,000 or the estimated amount of its cost responsibility for the facilities study, whichever amount is higher.

Upon completion of the facilities study, PJM provides a good faith estimate of the cost to be charged to the applicant for attachment facilities, local upgrades and network upgrades necessary to accommodate the project, and an estimate of the time required to complete construction of the facilities and upgrades. PJM will furnish an interconnection service agreement to be executed by the applicant. In order to proceed with an interconnection service agreement, the applicant must demonstrate within 60 days of receipt of the facilities study that it has met certain milestones. The applicant must show that it has entered fuel delivery and water agreements, if necessary, and that it controls any necessary rights-of-way for fuel and water interconnections. It must have obtained any necessary local, county, and state site permits; and signed an MOU for the acquisition of major equipment.

In addition, the regional transmission operator (RTO) may also require that a separate interconnection agreement be executed between the applicant and the RTO regarding construction of facilities and upgrades, parallel operation of the two systems, and other matters generally included in accordance with good utility practice. The agreements and studies referred to above are more fully described in Part IV of the PJM Interconnection, LLC Open Access Transmission Tariff available from FERC or from the PJM web site at http:/www.pjm.com.

3. PJM Markets

3.1 General

PJM is dedicated to making all facets of electric generation service that are practicable available on a competitive market basis, thus providing accurate pricing signals and access to these products for all participants in the new deregulated electricity environment. PJM's spot and ancillary markets offer market flexibility in that they support bilateral transactions by providing liquidity and risk management instruments, allow self-scheduling of supply, and provide spot market access. Based on the short but significant history of this effort, it would appear that PJM has succeeded in creating rational markets with the ability to adapt as market power or reliability issues arise. PJM currently operates six markets:

- Day-ahead energy market
- Real-time energy market
- Daily capacity market
- Monthly/multi-monthly (interval) capacity market
- Regulation market
- Monthly FTR auction market

PJM introduced market-clearing prices for energy tied to generation cost on April 8, 1998 and market-clearing prices based on competitive offers on April 1, 1999. PJM implemented a competitive, auction-based Financial Transmission Rights (FTR) market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include a monthly/multi-monthly market in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM plans to add a market in spinning reserves in 2002.

3.2 PJM Energy Markets

Generation owners in PJM can sell the output from their units in three ways: bid into the PJM day-ahead market, self-schedule their output to serve their own load, or sell their output directly (bilaterally) to another party. In 2001, approximately 36% of all energy used to serve PJM load was traded in the PJM energy markets.

PJM was a net importer of energy on a monthly basis for every month in 2001, and imported an average of 1,131 MW in each hour. Imports and exports respond to market prices. As detailed in the PJM Interconnection State of the Market Report – 2001, this activity supports the view that the PJM energy market is very liquid, and exists in the context of a much broader energy marketplace.

All anticipated generation and load in PJM must be scheduled through PJM at least the day before. Generators are contacted the day before and advised as to which (if any) of their bids were accepted, the hours they must run, and the amounts that they will be required to provide each hour. If a generator fails to supply the generation when required, it must replace that energy by purchasing it – either bilaterally or from the real-time energy market.

PJM runs two energy markets: the day-ahead market and the real-time market. All transactions made in the day-ahead market are financially binding, with adjustments for actual generation and usage made using the real-time market.

3.2.1 Day-Ahead Market

For 2001, the day-ahead market activity averaged 4,794 MW or 15% of average loads.

The day-ahead energy market is a financial market and is used to provide a hedge against price fluctuations (primarily congestion charges) in the real-time market. Based on load schedules submitted by all load-serving entities (LSEs) at least the day before the Operating Day, PJM calculates the expected energy needed at various locations (major busses) throughout the system, and accepts both sell and buy bids for the total amount needed each hour plus reserves. Then PJM stacks the sell bids in low-to-high price (or economic) order and assigns a price for electricity for each hour at each location for the following day in dollars per megawatt. The price for one megawatt of power during each hour the next operating day in the day-ahead market will be the lowest price bid satisfying the anticipated load requirement for that hour, plus any congestion charges expected to occur at that location. This hourly price is known as the Locational Marginal Price, or LMP. All successful bidders for that hour receive the price accepted, regardless of the price they bid.

PJM defines LMP as the "cost of supplying the next MW of load at a specific location, considering generation marginal cost, cost of transmission congestion, and losses." LMP values are the result of security-constrained economic dispatch operations, a method system operators have used to manage congestion for years. A least-cost security constrained dispatch algorithm determines the least expensive way to serve load while respecting transmission limits.

During periods of low demand, the LMP is generally the same at all locations. That is, none of the transmission capability is constrained. During periods of high demand, equipment problems, or system irregularities, the LMP can vary significantly from one location to another. This is especially so during peak system days.

Day-Ahead Energy Market Timeline

- Up to 12 noon – PJM receives bids and offers for energy for next Operating Day.
- 12 noon to 4 pm – Day-ahead market is closed for evaluation by PJM.
- 4 pm – PJM posts day-ahead and hourly schedules.
- 4 pm to 6 pm – Re-bidding period. Re-bidding period is for generation not selected for day-ahead market and lets them re-bid for regulation, operating, and spinning reserves. PJM desires to give preference to uncommitted capacity first.
- PJM continually re-evaluates and sends out individual generation schedule updates as required throughout the Operating Day.

3.2.2 Real-Time Market

For the full year 2001, real-time market activity averaged 6,563 MW during peak periods and 6,395 MW during off-peak periods, or 21% of average loads.

Electricity cannot be stored, and must be delivered the instant it is produced. Thus, any estimate of exactly how much electricity is going to be used at any given point will, by its very nature, be wrong. As mentioned above, in the day-ahead market PJM assigns LMP prices for each major bus in the transmission system that reflects the anticipated load conditions and constraint issues. In the real-time energy market, hourly prices are based upon the actual flow of electricity using sophisticated metering and modeling algorithms. Energy actually delivered by generators and LSEs to end-customers that is greater than that scheduled by them results in a charge equal to the amount of energy times the real-time LMP. A credit for the same calculation is given in the event more power is delivered than was forecast the day before.

In 2001 prices in the day-ahead market were higher than those in the real-time market for about 80% of the hours, yet the load-weighted total for real-time energy surpassed that of the day-ahead market despite being higher only during the remaining 20% of hours. This was due to the higher prices and usage associated with those hours. In the year ending June 30, 2002, day-ahead market prices were equal to or higher than real-time prices for 61% of the hours. The sum of day-ahead prices during this period was again less than that for real-time prices: $265,213 versus $271,318. Exhibit 3-1 and Exhibit 3-2 show the daily minimum and maximum values for both the day-ahead and real-time markets for the year ended June 30, 2002.

For a variety of reasons (congestion due to equipment failure, local loading conditions, etc.), real-time LMP values can show much more volatility than those in the day-ahead market. For example, during the record system peak day, August 14, 2002, the high hourly LMP at one bus was $1,739.93 and the low LMP at another bus was $-237.48. Exhibit 3-3 and Exhibit 3-4 show the differences between the PJM zone-wide integrated day-ahead market, PJM zone-wide integrated real-time market, the lowest-cost bus and highest-cost bus for the peak system day, and the same data for the system low day during the year ended June 30, 2002.

Exhibit 3-1
PJM East Day-Ahead vs. Real-Time LMP

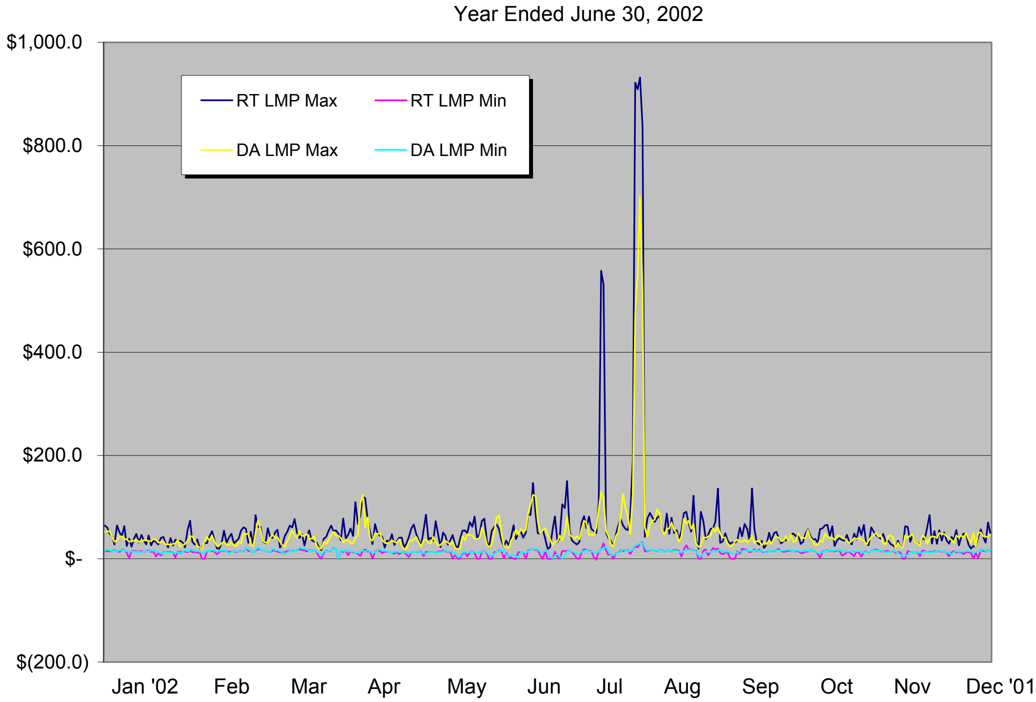


Exhibit 3-2
PJM East Day-Ahead vs. Real-Time LMP

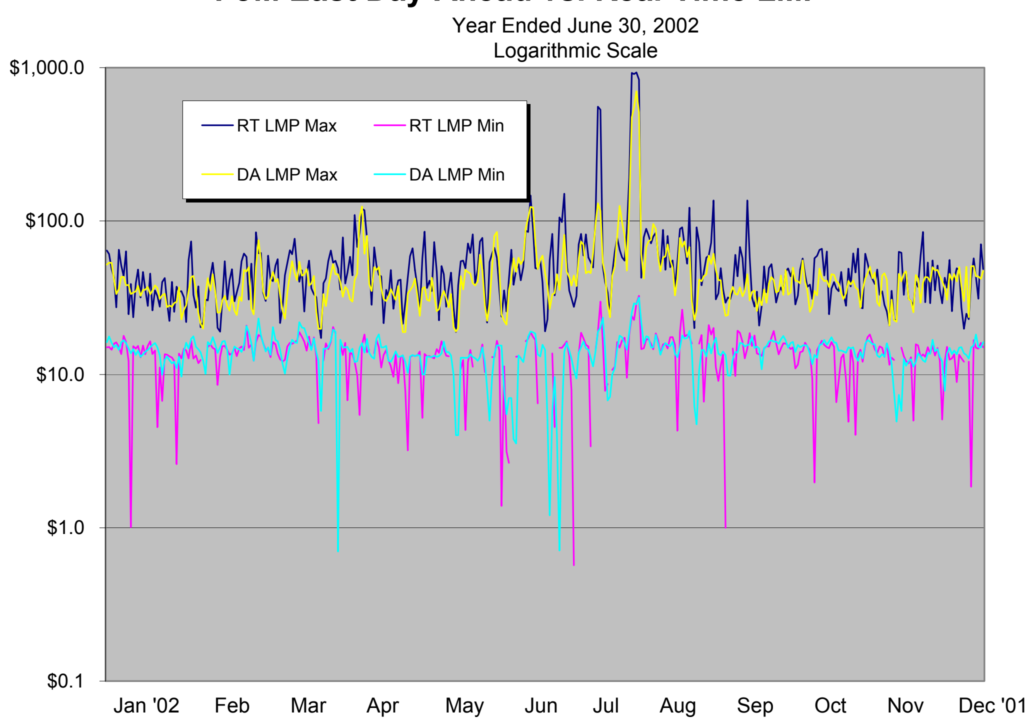


Exhibit 3-3
Comparison of PJM Spot Prices

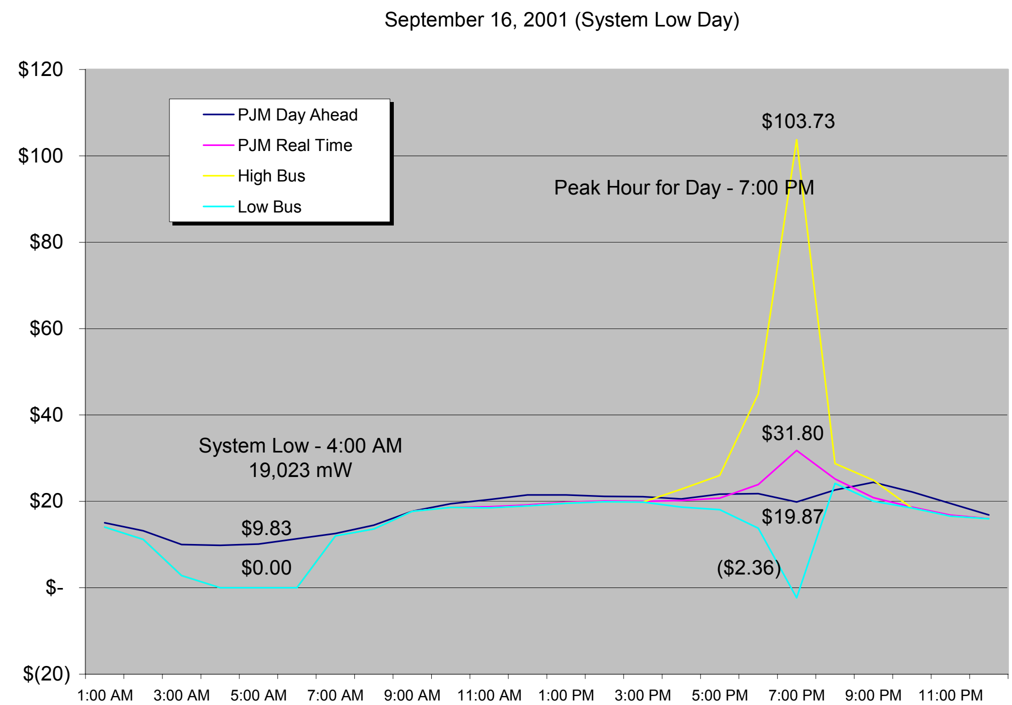
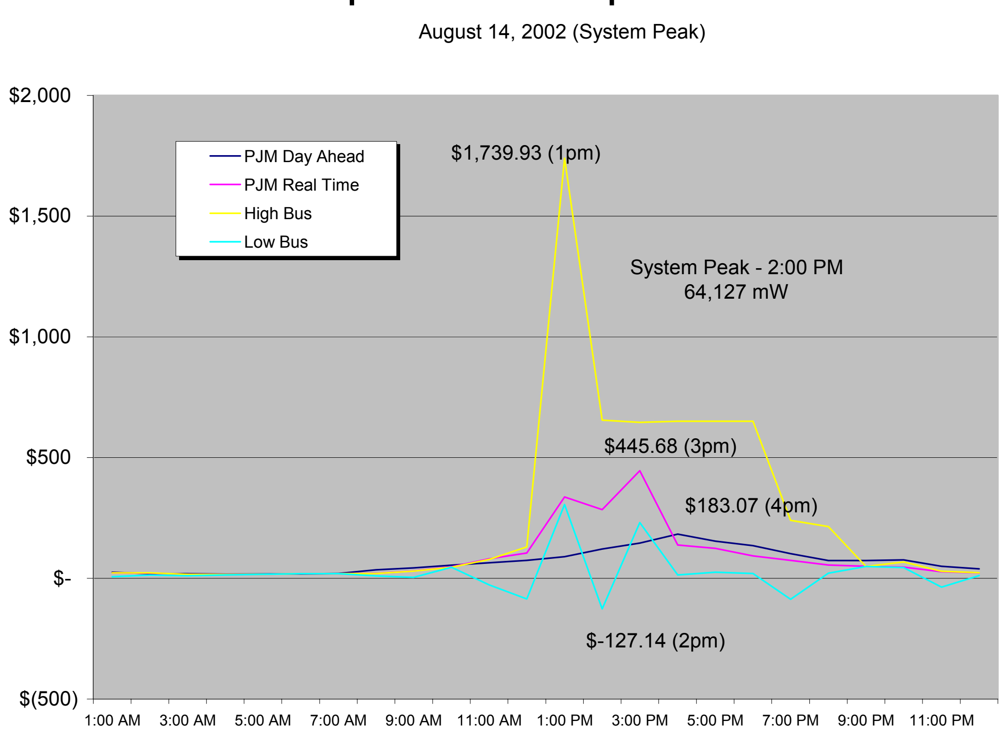


Exhibit 3-4
Comparison of PJM Spot Prices



3.2.3 Bilateral Energy Markets

Bilateral energy sales are those conducted directly between buyer and seller. PJM does not operate a bilateral energy market, but instead facilitates the use of bilateral energy sales by providing day-ahead and real-time markets to act as tools for balancing actual deliveries of generation against contracted-for deliveries.

As noted in the two previous sections, the PJM energy markets accounted for about 36% of all electricity dispatched in PJM in 2001. Bilateral transactions and energy delivered to load served by generation owners accounted for the balance of energy dispatched, or roughly 64%.

3.2.4 Prices and Demand

Real-time LMP pricing is based on actual system operating conditions. The PJM system model, or State Estimator, updates pricing and constraint information every minute. PJM uses the same model to simulate the day-ahead market, dispatch, system scheduling, and settlements. This means there is a high degree of consistency between LMP values and generator dispatch instructions.

PJM average energy prices increased in 2001 over 2000 for several reasons including increased fuel costs and relatively short periods of high load conditions. The hourly average system-wide LMP was 15.1% higher in 2001 than in 2000, $32.38/MWh versus $28.14/MWh, and 14.3% higher than in 1999. When hourly load levels are reflected, the load-weighted LMP of $36.65/MWh in 2001 was 19.3% higher than in 2000 and 7.6% higher than in 1999. The load-weighted results skew higher because more energy is consumed during high-price periods. When increased fuel costs are accounted for, however, the average fuel-cost-adjusted, load-weighted LMP in 2001 was 7.6% higher than in 2000, $33.05/MWh compared to $30.72/MWh. Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 7.6% higher in 2001 than in 2000.[1]

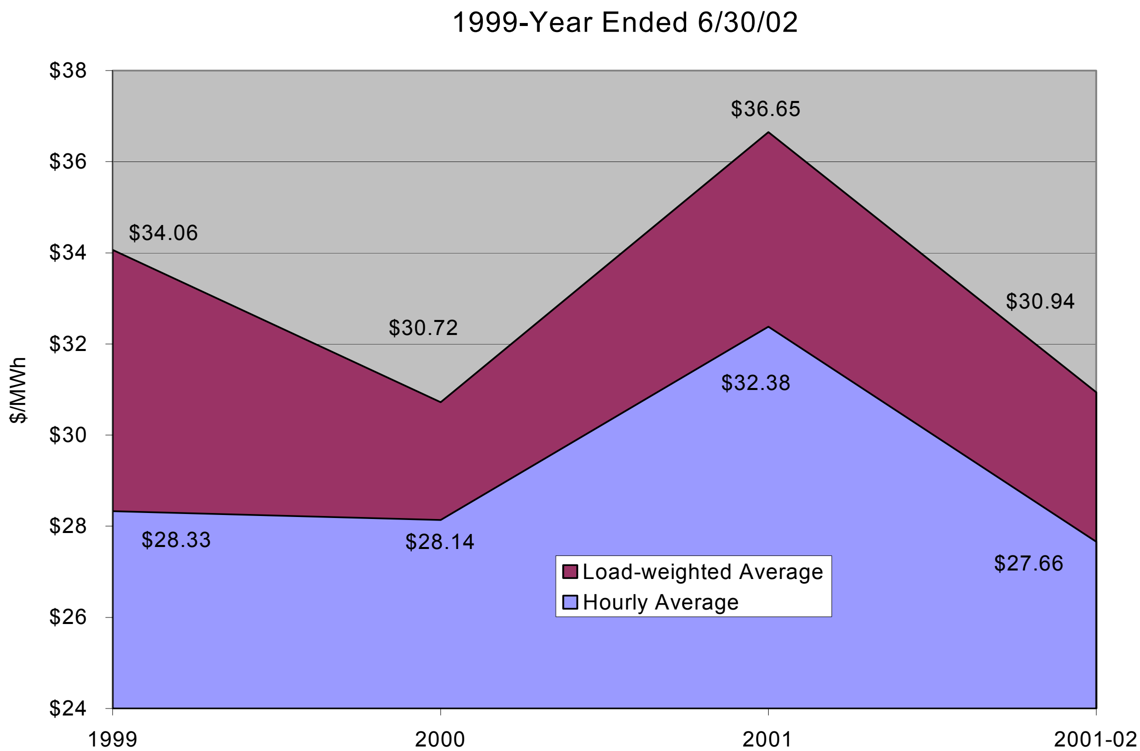
For the year ended June 30, 2002, PJM energy prices averaged $27.66, a decrease from calendar year 2001 of 15%, while the load-weighted average was $30.94, a decrease of 16% over the calendar year prior. This decrease is due mainly to a combination of a mild winter and the addition of new generation capacity and, to a lesser degree, a soft economy. Exhibit 3-5 reveals a comparison of PJM East spot prices for the years 1999 through June 30, 2002.

High price spikes in the PJM energy markets have dampened somewhat over the past three years. In 1999, prices in the day-ahead market were above $900/MWh for 33 hours, above $500/MWh for 60 hours, and above $150/MWh for a total of 91 hours.

[1]*Source: PJM Interconnection State of the Market- 2001*

In 2001, PJM day-ahead prices exceeded $500/MWh for only 9 hours and $150/MWh for just 44 hours. In the 2001 real-time market there were 10 hours above $500/MWh and 60 hours greater than $150/MWh. All hourly prices above $150/MWh occurred in the summer of 2001. For the year ending June 30, 2002, those numbers remained virtually the same, with no additional day-ahead or real-time prices above $150/MWh. This was probably due to additional capacity coming on-line, coupled with lower demand in the winter. The highest prices for the year ended June 30, 2002 occurred on August 9, 2001, with a high of $701/MWh in the day-ahead market, and $932.27/MWh in the real-time market.

Exhibit 3-5
Comparison of PJM Spot Prices



There is a strong correlation between price and demand in the PJM markets. Exhibit 3-6 and Exhibit 3-7 indicate day-ahead high and low prices, and daily high and low loads for the year ended June 30, 2002.

Exhibit 3-6
PJM East Load and Spot Price (Day-Ahead LMP)
July 2001- June 2002
(logarithmic LMP scale)

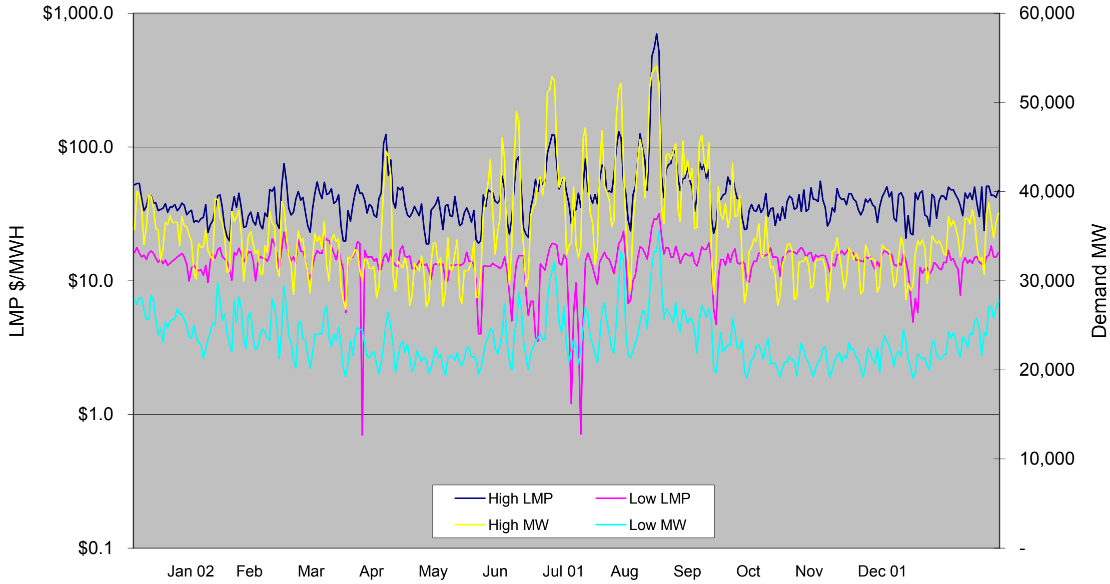
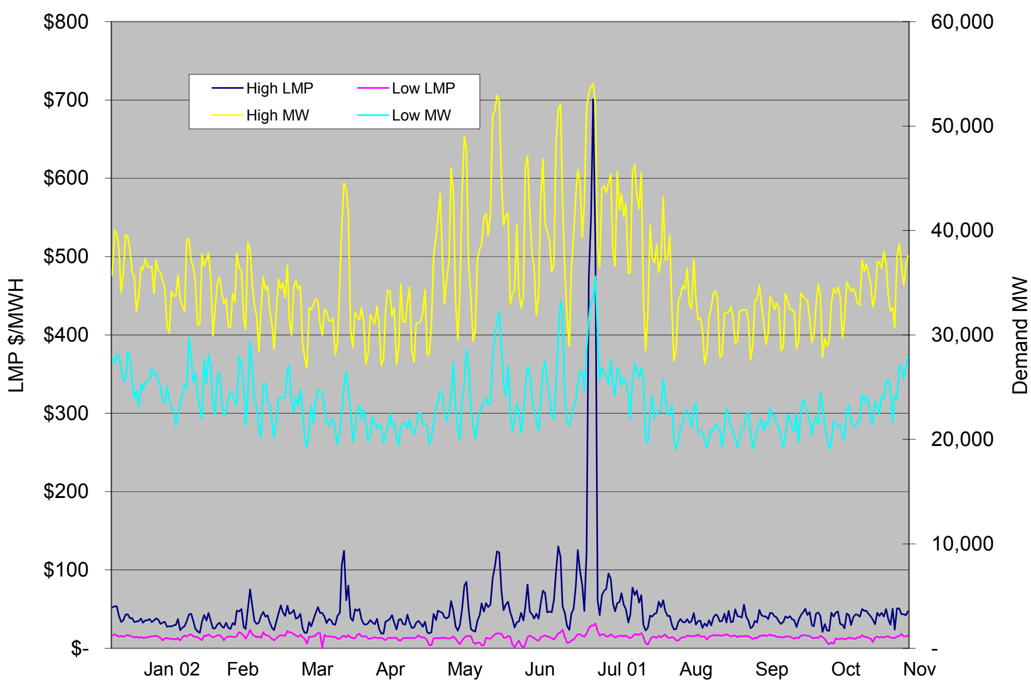


Exhibit 3-7
PJM East Load and Spot Price (Day-Ahead LMP)
July 2001- June 2002



The following charts show the correlation between price and demand over a three-year period. They also show a rational association between the two, supporting the viewpoint that PJM has been effective at creating competitive energy markets.

Exhibit 3-8
PJM East Day-Ahead LMP vs. Demand

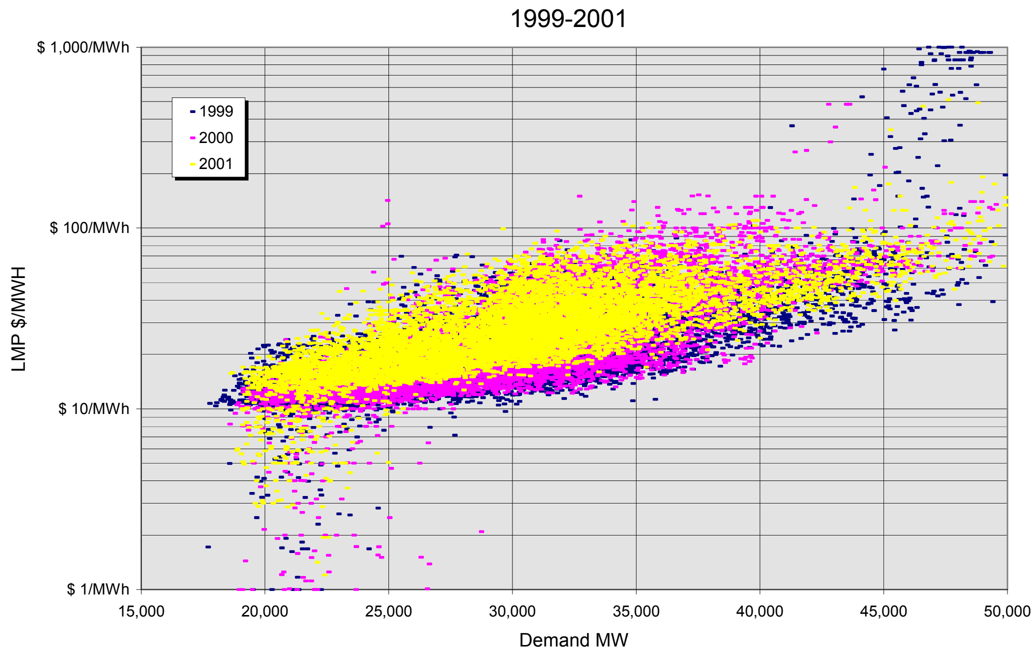
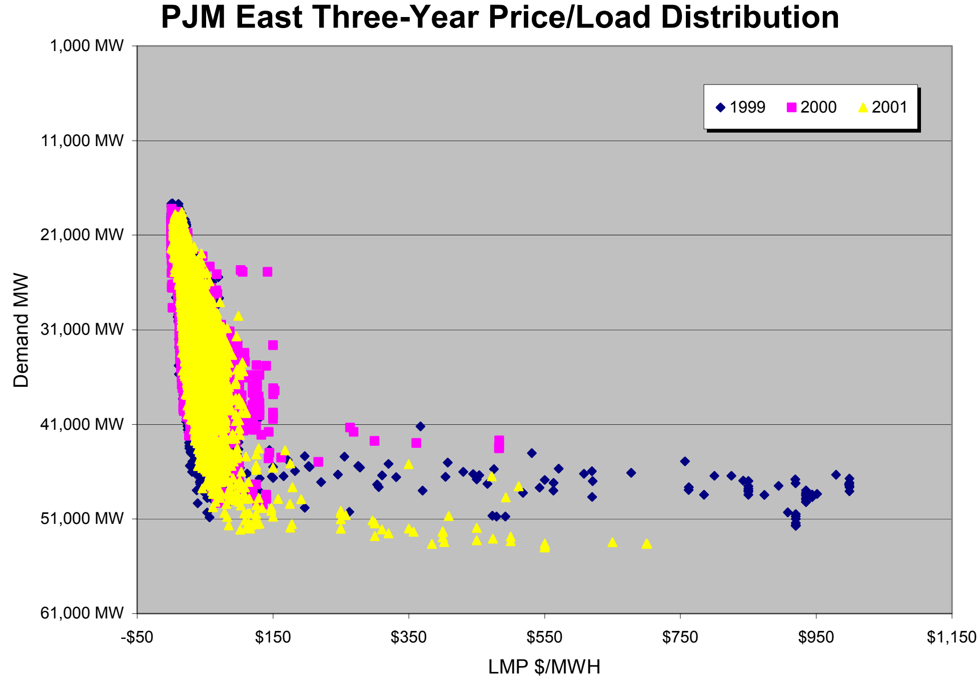


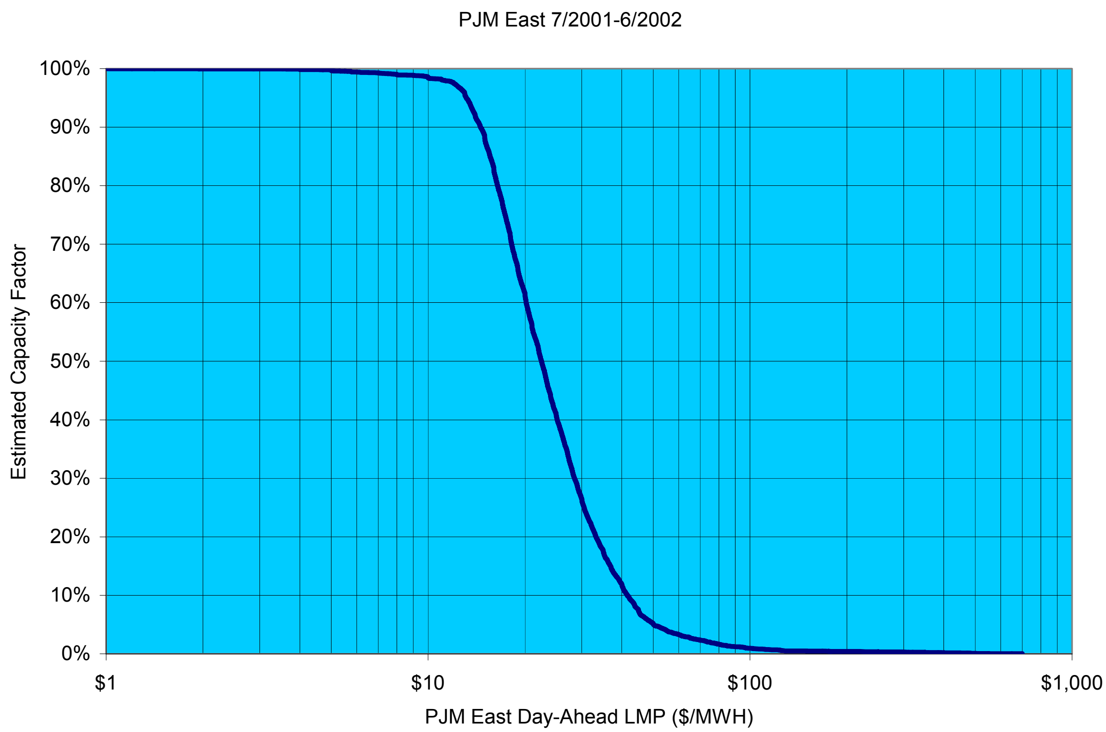
Exhibit 3-9
PJM East Three-Year Price/Load Distribution



3.2.5 Energy Prices and Unit Dispatch

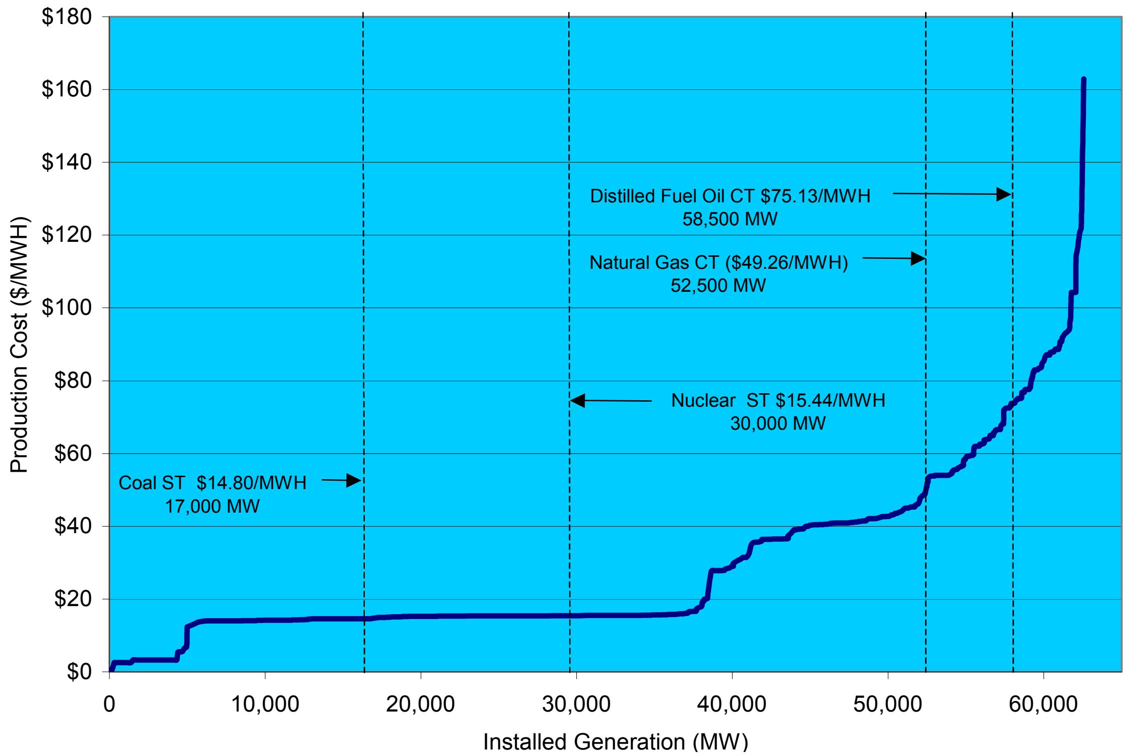
Exhibit 3-10 shows the percentage of hours in which the day-ahead LMP for the year ending June 30, 2002 was equal to or less than the price indicated at the bottom. This can be used to determine the maximum number of hours a given unit might be dispatched if bid into the market based on its actual operating costs.

Exhibit 3-10
PJM East Estimated Capacity Factor vs. LMP



A more concrete illustration of the type of unit likely to be providing the marginal unit of generation at any given point during the year ended June 30, 2002 is shown as Exhibit 3-11. In it we see the level of load in PJM East that yielded day-ahead LMP values equal to or greater than those associated with four types of generators that currently comprise 70% of the generating capacity in PJM East. The chart shows each unit type, its weighted-average operating cost from the GEMSET PJM East stacking order, and the minimum level of load required to match or beat those estimated operating costs. These units are also used in the revenue calculations found in Section 1.

Exhibit 3-11
GEMSET Estimate of PJM East Production Costs And Load Dispatch Levels



3.2.6 Energy Market Demand Side

One of the challenges of building competitive electric markets is the lack of elasticity of demand. In other words, there is as yet very little ability for end-users to control demand in such a way as to provide meaningful pricing signals to sellers of generation. This lack of ability to control demand has been cited as one of the primary reasons for maintaining an offer cap (of $1,000/MWh) in PJM and other wholesale power markets. It is widely recognized that wholesale energy markets will work better when a significant level of potential demand side response is available in the market. In order to develop such demand side response it is necessary to increase the level of load that can see prices in real time, that can react to prices in real time and that can benefit from reacting to prices in real time. This is a complex issue that includes a variety of institutional barriers ranging from jurisdictional issues to fundamental incentive issues. It is difficult to measure the reaction of loads to prices if loads do not have meters that record use by time period. As a result, it is difficult for loads to react to prices in real time and difficult for loads to benefit from reacting to prices in real time. It is not clear which market entity (EDC, LSE, End-user), if any, currently has adequate incentive to invest in the installation of meters necessary to have effective demand side participation.

PJM initiated a Demand Response Pilot program for both emergency and economic response in 2001. Though limited in enrollment, it demonstrated the potential impact of effective demand side participation in the market. The maximum hourly reduction in load that resulted from PJM programs was 1,858 MWh during 2001. The average hourly load reduction during hours when a PJM DSM program was called upon was about 1,200 MW, or about 2.2% of peak load. The average price impact of this load reduction was about $135 per MWh. As a measure of the potential of DSM programs to impact price, there would have been a further reduction in price of about $300 per MWh if an additional 2,000 MW of load reductions had been made during the hours when existing programs were activated during the summer of 2001.[3]

3.3 PJM Capacity Markets

PJM requires each load-serving entity (LSE) to own or acquire Capacity Resources equal to the peak load that it serves plus a reserve margin (currently 19% in PJM East and 11.4% in PJM West). Capacity is a separate and distinct commodity from energy. In an ideal world, capacity charges would cover the capital cost of building generation, while energy charges would cover the variable costs (fuel, maintenance, labor, and other operating costs) of generating electricity. In the real world, however, capacity in the PJM markets clears at a price more tied to the value of that capacity at a given point in time, and so can be very high when generation is scarce or opportunities for greater energy revenues exist in neighboring areas, and low when it is abundant or there is no alternative market currently yielding higher energy prices. In theory, a separate capacity market may not be necessary, but in practice it serves to help support long- and short-term generation supply requirements while allowing non-generation-owning market participants (competitive retail suppliers) to fulfill their PJM capacity obligations and sell off capacity when no longer needed.

LSEs can acquire capacity in three ways: by buying or building units, by entering into bilateral arrangements with third parties, or by participating in the capacity credit markets operated by PJM. Generation owners pledging the availability of their assets to PJM receive revenue for selling capacity credits in units of one MW/day. These generators are referred to as Capacity Resources, and must offer their energy into the PJM day-ahead market. They can sell their energy outside PJM only if they retain the right to recall it in case of emergency. In this way capacity credits act as a call on energy during periods of generation shortage.

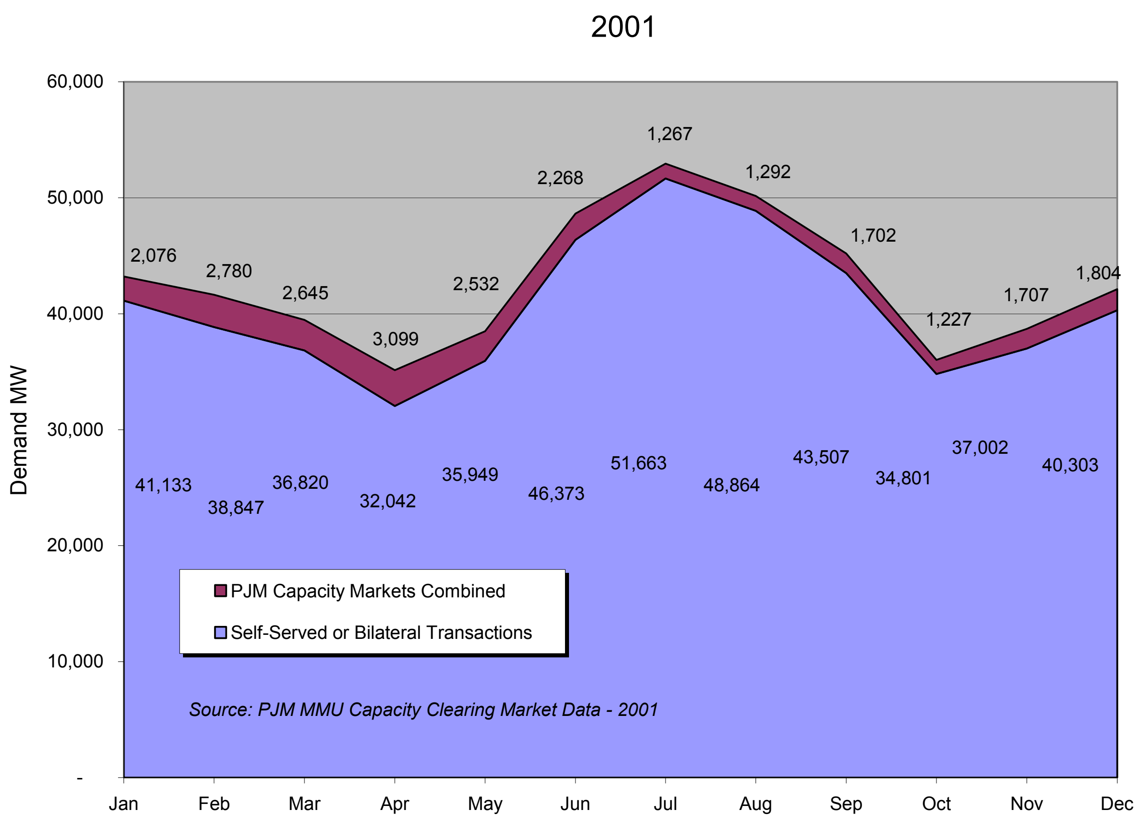
In PJM, all capacity is accounted for. LSEs are assigned a capacity obligation number for the load they serve (as determined by PJM in cooperation with EDCs) or face paying what is

3 *PJM Interconnection State of the Market Report – 2001.*

called the Capacity Deficiency Rate, or CDR, for the shortfall amount for the remainder of the interval (up to five months) in which the short position occurred. The CDR is currently $174.73 MW/day.

The PJM capacity credit markets provide the mechanism to balance the supply of and demand for capacity not met via the bilateral market or via self-supply. The vast majority of capacity traded in PJM occurs directly between participants. In 2001 more than 95% of capacity requirements were satisfied by those who owned their own capacity or acquired it in bilateral deals, as illustrated in Exhibit 3-12.

Exhibit 3-12
PJM East Capacity – Bilateral vs. PJM Markets



There are two capacity credit markets in PJM East, the daily capacity market and the monthly/multi-monthly capacity market. The monthly/multi-monthly capacity market is an auction scheduled periodically where Capacity Resources and LSEs submit buy and sell bids for capacity credits extending for periods of one or more months. Capacity Resources wishing to be able to earn a share of the CDR receipts bid for intervals of between three and five months. These interval periods are January-May, June-September, and October-December. Capacity Resources willing to waive the CDR revenue opportunity may bid in for other periods as short as one month. The daily market for capacity is essentially a balancing market, allowing LSEs to buy or sell capacity credits to make up for changes in their respective loads.

Capacity bids are submitted using the Internet tool "PJM eCapacity." This computer tool enables generators to create bilateral capacity transactions or submit capacity modifications to increase or decrease the installed capacity rating of a unit. The application also allows LSEs to enter Active Load Management (ALM) modifications, and view peak load and obligation data.

There are separate capacity markets in PJM East and PJM West. PJM East capacity is known as "installed capacity" and is not linked to specific units, but rather takes the annual average unit availability and allows generation owners to sell credits that may be fulfilled by their own units or purchased in order to satisfy the requirement. The capacity in PJM West is called "available capacity" as it refers to real-time unit-specific availability, and is sold by generation owners to LSEs on a unit-specific basis. PJM is working toward combining these two methodologies as soon as possible. The PJM West capacity credit markets are still quite new (begun in early spring 2002), and are lightly traded. The average daily clearing price was $99.86 per MW/day as of August 21, 2002, and the average monthly-multi-monthly price was $10.04 per MW/day. These numbers represent very small trades (less than 1,000 MW traded in total since April 1, 2002) and should not be considered indicative of any significant trend.

PJM states that in January 2001 there was evidence that a single market participant was able to exert market power in the PJM capacity markets. This entity bid in more capacity into the daily market than was necessary at or above the CDR. Under the then-current rules, the revenue from CDR charges was distributed to holders of unsold capacity. In this case the entity in question was able to either receive the lion's share of these revenues or sell their capacity at or above the CDR. As a result, PJM changed the rules governing the capacity markets. As of June 2001, capacity holders must offer their capacity for longer intervals (as described above) if they wish to receive capacity revenue and benefit from CDR payments. Auctions for each interval are held well in advance of the beginning of these periods. Capacity Resources choosing to offer their capacity in these markets must do so for the entire interval period or be unable to collect CDR revenue, which is now divided among market participants. LSEs falling short on their capacity credits must now pay the CDR for the shortfall amount for the remainder of the interval period rather than on a daily basis.

The result of these changes has been that capacity prices have come down considerably, with capacity credit clearing prices averaging $69.53 per MW/day for the second half of 2001. The impact of additional Capacity Resources coming online plus the rule changes have caused the capacity markets to drop again significantly in 2002, with the daily clearing price averaging under $1.00. *These prices do not reflect the price of the bilateral market, where the vast majority of capacity is traded. These prices are not made public.*

Exhibit 3-13 shows the average daily and monthly clearing prices in the PJM capacity credit markets in 2001, plus a line marking the weighted average of the two. The effect of the alleged market power exertion is clearly reflected during the high daily clearing prices in the January through March timeframe. Monthly capacity clearing prices rose sharply as the new rules were about to be invoked, perhaps because LSEs wanted to lock up their obligation before they exposed themselves to the new, much higher CDR penalties. The daily balancing market was lightly traded as a result following June 1, and prices in both markets fell considerably as new generation came online and Capacity Resources bid into the new interval markets.

Exhibit 3-13
PJM East Capacity Credit Markets
2001

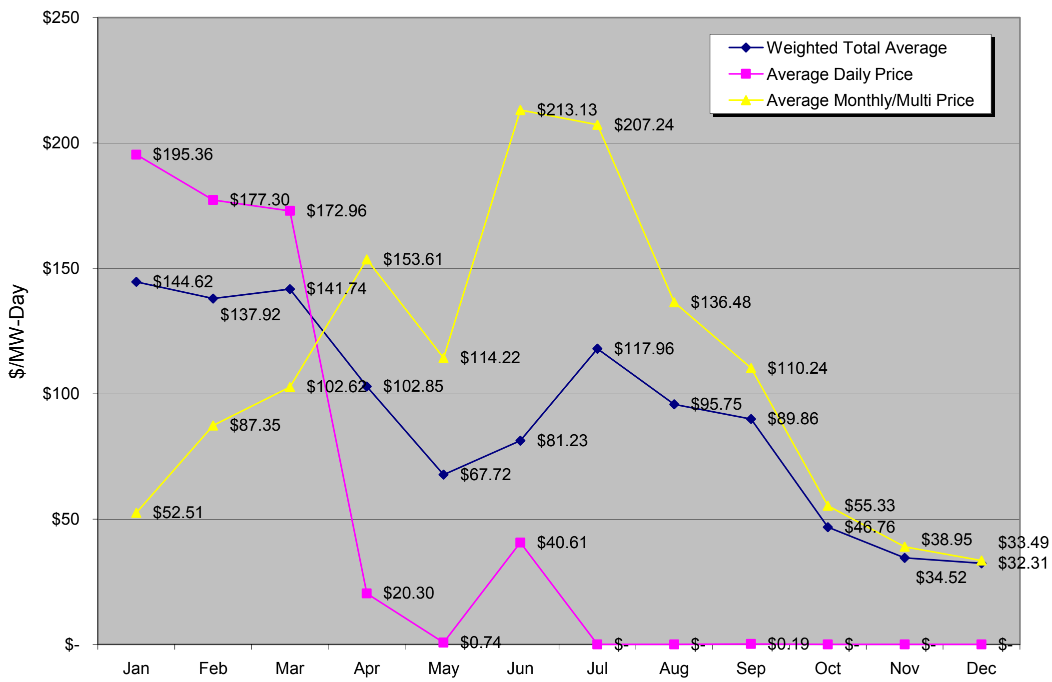
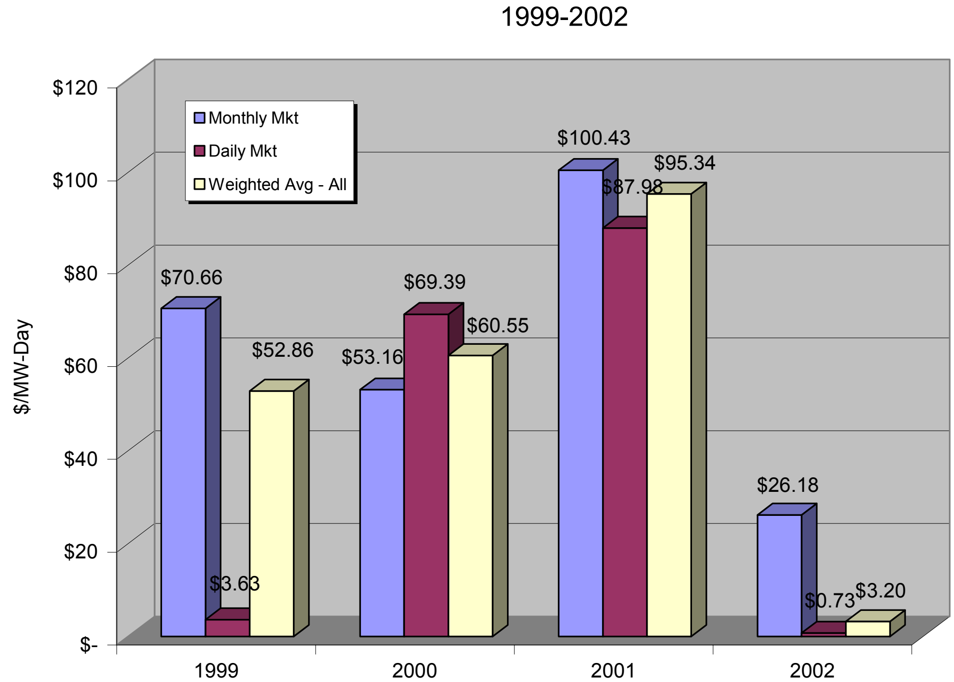


Exhibit 3-14 illustrates averages in both PJM East capacity markets for the past three calendar years and up to August 21, 2002.

Exhibit 3-14
PJM East Capacity Credit Market Clearing Prices



Additional changes in the capacity market are being considered by PJM as part of the ongoing Standard Market Design (SMD) discussions, with the goal of providing clearer incentives to build new capacity in a timely manner. One idea being discussed is that new generation could possibly auction off their capacity forward several years into the future, and that generators that have collected ample "tolls" in the form of capacity credits be limited in their ability to charge for capacity after the capital expenses of construction have been paid for. Another is the notion that LSEs can supply their obligation by projecting their capacity needs forward three years into the future and contracting for adequate capacity (known as Resource Requirements) to cover their needs plus 12% reserves in one or more of several ways: contracting with generators, building their own generation, providing demand response or building new transmission assets. *This is both a critical and dynamic issue and should be carefully tracked as SMD discussions go forward.*

3.4 PJM Ancillary Services

Ancillary services are services necessary to support the reliability of the electrical system by providing for dynamic management of generation, frequency, and reactive power (VAR). FERC order number 888 defines six ancillary services:

- Scheduling, System Control and Dispatch Service
- Reactive Supply and Voltage Control from Generation Sources Service
- Regulation and Frequency Response Service
- Energy Imbalance Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

As part of its effort to create price transparency and apply market forces to the unbundled elements of electrical delivery, PJM has instituted a market for Regulation and intends to do so with spinning reserve in the fall of 2002.

3.4.1 PJM Regulation Market

PJM instituted a market for Regulation in June of 2000. As detailed in a "PJM Energy Market Model" presentation dated February 8, 2002, regulation is a "variable amount of generation capacity under automatic control that is operated independently of the economic dispatch signal and can respond within five minutes." Qualifying generating units provide "fine-tuning" for the system that corrects for small load changes that cause the power system to operate above or below 60 Hz for a sustained period of time. Governors on qualifying units respond to minute-by-minute changes in load. The total requirement for regulation is broken into on- and off-peak pieces for each Operating Day. The peak element is estimated at 1.1% of forecast peak load, and the off-peak requirement is figured at 1.1% of the valley load forecast. In 2001 this amount ranged between 200 and 600 MW daily. Only 144 of the 540 generating units in PJM were qualified to provide regulation in 2001, but these units routinely bid more regulation service into the market each day than was required. LSEs can satisfy their regulation requirements by purchasing it bilaterally, self-scheduling their own resources, or purchasing them through PJM's Regulation market.

PJM's Regulation market is run as follows. Each day qualifying generation sellers inform PJM of their availability and bid price, and PJM determines which units shall be in reserve and to what level, then stacks them in economic order and assigns a clearing price for the next day's regulation. This is known as the Regulation Market Clearing Price, or RMCP. Regulation payments are based on per-event dispatch, and are paid out at the higher of the RMCP or the individual generator's offer price plus the opportunity cost (LMP). Regulation offers may not exceed \$100/MWh. Regulation obligation can be satisfied by bilateral contract, self-scheduling, or spot purchase.

The regulation market for August 2002 (as of the 21st) yielded an average \$51.20/MWh plus an average additional opportunity cost (when LMP is greater at the unit's bus than the market clearing price) payment of \$13.80/MWh to its providers.

PJM West has a separate regulation market with one significant difference. Regulation in PJM West must be bid in at unit marginal cost expressed in \$/MWh.

3.4.2 Operating Reserves

The purpose of operating reserves is to supply reserves able to serve load in the event of a system contingency. Operating Reserves are probabilistically determined based upon historical load levels. Currently, PJM East requires 19% of daily peak load in reserves. That number is 11.4% in PJM West. Operating reserve requirements are modeled in both day-ahead and real-time energy markets. There are two types of operating reserves: spinning reserve and supplemental reserve.

Spinning reserve is defined as generation capable of producing output within 10 minutes. This is accomplished through a combination of units synchronized with the system plus generators with quick-start capabilities. Ten-minute start units dispatched are paid the highest of: real-time LMP, historical LMP at the unit's bus, operating cost plus 10%, or some other amount determined between the seller and PJM. Spinning reserve can be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing combustion turbines (CTs), CTs running at minimum generation and steam units scheduled day ahead to provide spinning reserves. PJM plans to introduce a market in spinning reserves during 2002. It is slated to be similar in concept to the current regulation market. LSE obligations will be calculated based on load ratio share of the spinning requirement. Those with obligations will be able to fulfill them by:

- Self-scheduling spinning reserve on owned resources.
- Trading spinning capability bilaterally.
- Purchasing from the spinning market.

Supplemental reserve is defined as generation not synchronized with the system but able to begin supplying energy within 30 minutes of a dispatch signal. Generation units selected by PJM with additional capacity to serve load the day after are paid for the difference between their scheduled load times their offer price, minus any startup or no-load costs, and the total value of their spot market energy bids at the day-ahead LMP applying to their bus. In other words, units designated for reserves are made whole on a daily basis if the energy payment does not equal offered prices. PJM's Market Monitoring Unit (MMU) estimates that the average annual gross revenue from operating reserve sales in 2001 was $4,275 per MW of capacity for each average PJM Capacity Resource.

3.5 Financial Transmission Rights (FTRs)

PJM instituted a market for Financial (formerly Firm or Fixed) Transmission Rights (FTRs) in 1999. PJM defines FTRs as "a financial contract that entitles the holder to a stream of revenues (or charges) based on the hourly energy price differences across the path." The purpose of FTRs is to create a forward energy market by providing a mechanism to manage price risk caused by LMP differences during periods of transmission congestion, insulate firm transmission customers from exposure to transmission congestion costs, and to allow energy suppliers to purchase protection from transmission congestion charges on a specified path. FTRs are:

- Defined from source (generator or hub) to sink (end-users).
- Financially binding.
- Determined by hourly LMPs (economic value).
- A financial entitlement, not a physical right.
- Based on MWs of transmission reservation separate and independent of energy delivery.
- Credited when in same direction as congested flow.
- Charged when configured opposite direction as congested flow.
- Paid for by collection of congestion charges.

FTRs may be awarded, traded bilaterally, or bought in the PJM FTR auction. Holders of FTRs are paid through distribution of congestion charges paid by market participants that do not have FTRs on the path in question.

At this time, changes to both the FTR allocation and revenue distribution are being contemplated in order to allocate FTRs more fairly, share more benefits with the end-users that paid for the transmission system, and to encourage Independent Transmission Companies (ITCs) to invest in the infrastructure necessary to accommodate load growth and replace aging equipment.

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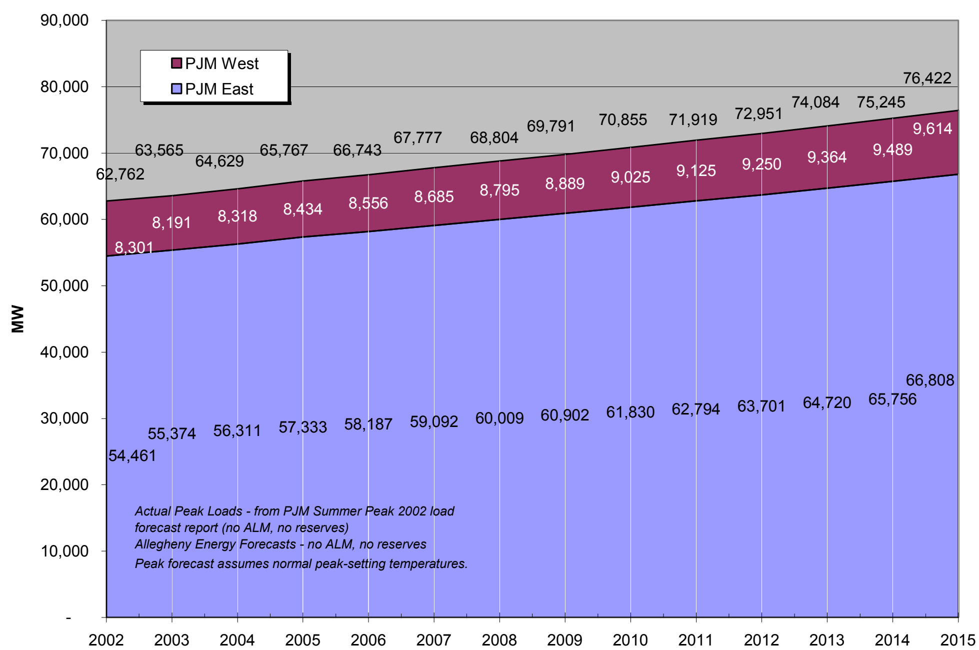
4. Load Forecasts – Capacity Additions

4.1 Load Forecasts

The PJM East weather-normalized summer peak for 2001 was 54,240 MW, an increase of 3.6% from the 2000 normalized summer peak. The projection for the 2002 PJM summer peak is 54,461 MW, an increase of 221 MW, or 0.4%, from the 2001 normalized peak (though this has been eclipsed by actual conditions). Summer peak load growth for PJM is projected to average 1.6% over the next 10 years. The PJM summer peak is expected to reach 63,701 MW in 2012, a 10-year increase of 9,240 MW. Winter peak load growth for PJM is projected to average 1.5% over the next 10 years. The PJM winter peak load in 2011/12 is forecast to be 51,217 MW, a 10-year increase of 7,146 MW. Based on the combined zonal forecasts contained within this report, PJM will continue to be summer peaking during the next 10 years. Annual energy growth for PJM is projected to average 1.5% over the next 10 years. Annual net energy for PJM is forecast to reach 315,981 GWh in 2012. The PJM load factor is projected to remain constant at approximately 56%.[2]

Exhibit 4-1
PJM Combined Peak Summer Load Forecast



[2] PJM Load Forecast Report – July 2002

4.2 Capacity Additions

New power plant projects take years to develop, license, and build, so there is by necessity a significant lag for new generation to come on line. The level of planned new generation in the PJM area reflects the conviction that incentives provided by the combination of revenues from the PJM energy, capacity and ancillary services markets plus operating reserve payments will be adequate to create sufficient net revenue to proceed with construction of new assets for the future. This report looks at two sources for estimating the amount and type of generation that will be built in PJM – the PJM generation queue and PJM's MAAC 411 form. The PJM queue is actually a series of nine queues, identified by the letters A through I, arranged by date of application for a feasibility study. Much of this generation will never be built. As of June 15, 2002, about 56,000 MW of capacity was in queue for construction through 2007. Exhibit 4-2 illustrates that about 44% of the projects originally in these queues had been withdrawn at that time.

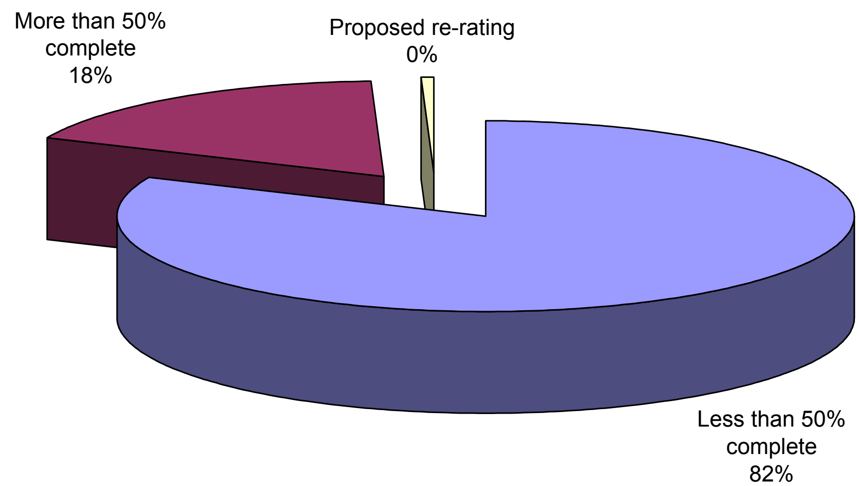
Exhibit 4-2
PJM Combined Generation Project Queue

Queue	Closing Date	Original Projects	Remaining Projects	Projects Withdrawn	MW Remaining
A	4/15/99	62	34	45%	11,218
B	11/30/99	60	28	53%	8,008
C	3/31/00	24	9	63%	2,333
D	7/31/00	35	22	37%	4,600
E	11/30/00	46	16	65%	3,835
F	1/31/01	10	6	40%	1,291
G	7/31/01	76	43	43%	10,922
H	1/31/01	36	32	11%	8,542
I	7/31/02	11	11	0%	5,017
		360	**201**	**44%**	**55,766**

This comes as no surprise to PJM's System Planning Group, which estimates that, as a rule, only 25 to 30% of projects in the generation queue actually end up serving load. To underscore this, a re-check of queue status on August 13, 2002 revealed that another 12,130 MW of generation requests had been withdrawn.

Despite this drop-off, PJM is steadily adding capacity. The Mid-Atlantic Area Council (MAAC), which is essentially PJM East, must report to NERC annually on a variety of data, included among which is a summary of planned generation in the region. The draft response to the 2002 NERC data request (formerly MAAC EIA 411) lists 36 projects with a total of 11,439 MW of capacity as having a status of being under construction, thus are likely to be put into service.

Exhibit 4-3
PJM East Planned Generation by Status



Source: 2002 NERC Data Request (formerly MAAC EIA 411) - Draft

Exhibit 4-4 is a chart of the load growth forecasts for PJM (East and West) showing reserves, the level of generation in queue as of August 13, 2002, and planned generation numbers derived from the NERC Data Request 2002 Draft Report for years 2002-2004 and an estimate of the percentage of units in queue actually being built (from PJM System Planning) for PJM West 2002-2007 and PJM East 2005-2007.

Even given the different observations, it seems evident that there will be sufficient generation capacity to accommodate the short-term load growth in PJM. Some would argue this demonstrates the effectiveness of the ICAP markets to encourage timely construction of generation, while others would point to the recent additions and new construction as a delayed result triggered by high prices in 1999. In either case, none would argue that there is currently a strong signal discouraging future construction in the form of low capacity prices.

Exhibit 4-4
GEMSET Load and Generation Forecast Estimates – Combined PJM

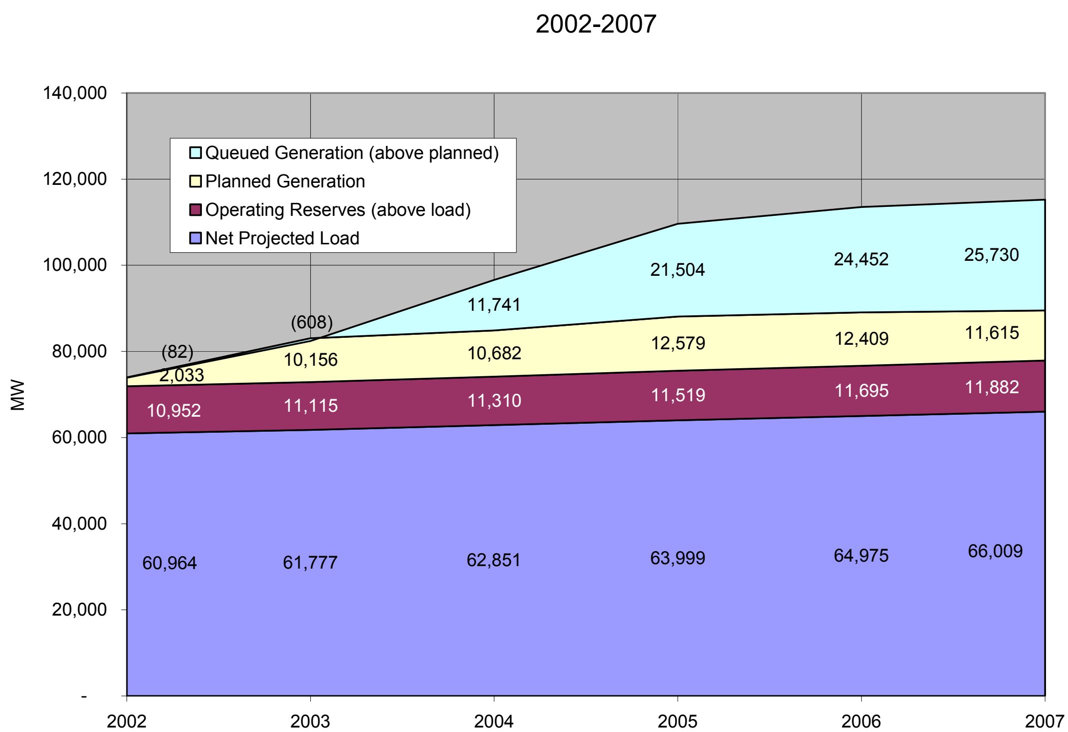
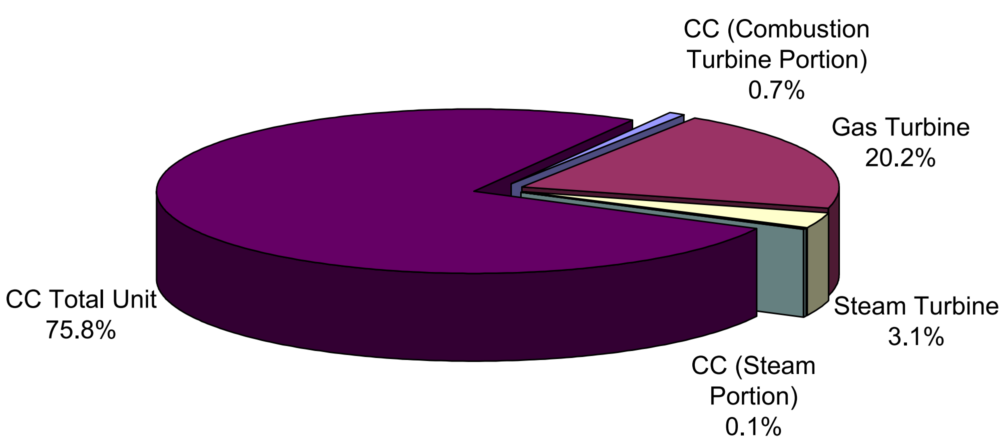


Exhibit 4-5 illustrates the breakdown of PJM East planned generation by Prime Mover. Virtually all of the planned generation is combined cycle or combustion turbine. There are no baseload units currently in queue through 2007.

Exhibit 4-5
PJM East Planned Generation by Prime Mover



Source: 2002 NERC Data Request (formerly MAAC EIA 411) - Draft

5. Generator Revenue Opportunities

Generators in PJM derive their revenue from four main sources: energy sales, capacity credit sales, ancillary services, and operating reserves. This section explores the historical potential (in 2001) for revenue among four different generator types that together comprise almost 70% of the generation fleet in PJM East. It also underscores the importance of the capacity and ancillary markets in ensuring adequate supplies, especially among mid-merit and peaking units.

5.1 2001 Net Revenue

PJM's State of the Market Report 2001 detailed the average net revenue opportunities among the four sources noted above in PJM East for calendar year 2001. Net revenue measures the contribution to capital costs paid by loads and received by generators from PJM markets and can be viewed as an indicator of the relative profitability of an investment in generation as well as a measure of the incentives to build new generation. Net revenue represents revenue after variable costs, fuel, and variable operation and maintenance (O&M) expenses are covered. Net revenue is available to cover fixed costs, including a return on investment, depreciation, and fixed O&M expenses. In an ideal market, net revenue would equal the total of all these fixed costs for the marginal unit, plus an acceptable return on investment. For continued reliable electric supply, investors in new generation must be reasonably assured of an adequate return on their investment to encourage new construction. To maintain low electric prices, the amount of this return must not be usurious. It is hoped that, with a large number of market participants, the resulting competitive market will establish a balance between adequate margins and reasonable return.

According to PJM, the net revenues from all markets in 2001 would have been adequate to cover the fixed costs of peaking units having operating costs of $45/MWh. This is based upon average gas costs for the year and the heat rate for a peaking unit. The data suggest that this may have been primarily the result of high capacity market prices in the first half of 2001.

It is important to note that these comparisons are valid as a snapshot of the market as it existed in 2001, and have limited value when looking forward any appreciable time. Some caveats are:

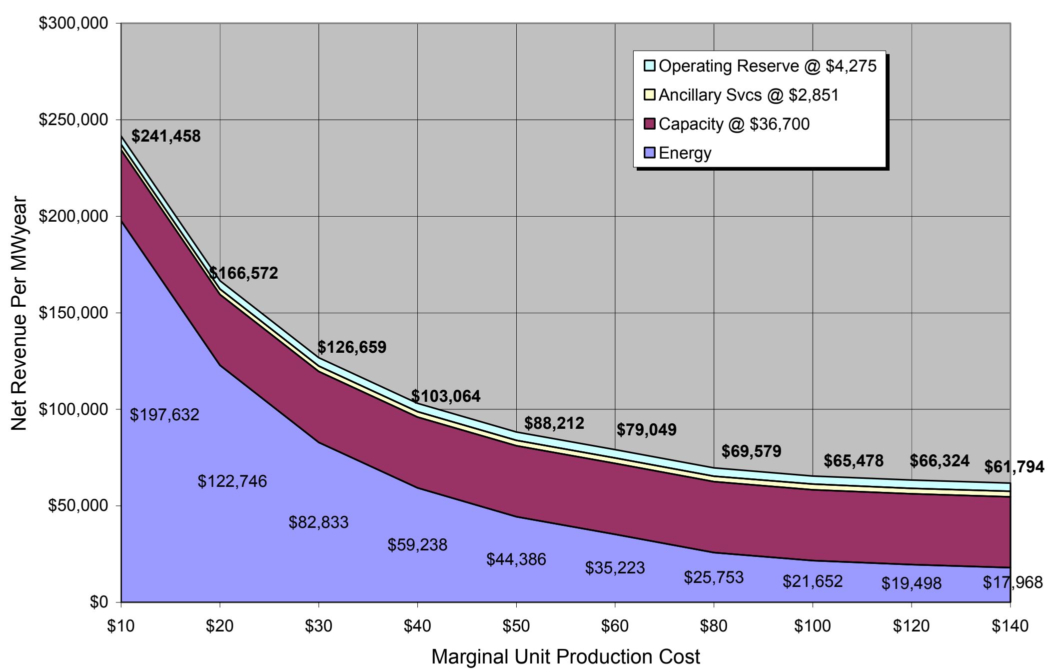
- Different units have different operating characteristics and may not have similar reserve and ancillary service opportunities.

- Bilateral Agreements and self-served load (as opposed to energy cleared in the PJM spot markets) account for more than 60% of energy delivered in PJM, and more than 95% of capacity transactions, though forward energy prices (generally reflecting bilateral deals in the broker market) on the Intercontinental Exchange and the now-withdrawn NYMEX PJM West commodity have tracked closely to PJM spot market averages over time.

- Due to changes in trading rules and the presence of additional capacity in the region, PJM capacity credit markets have softened significantly in the past year, with the average going from $95.34 per MW/day to an average of $3.20 per MW/day. Bilateral capacity deals are more difficult to track against the PJM markets. Bilateral capacity has traded in $60 to $90 per MW/day range over the past few years, with a more recent quote by a buyer in PJM as being approximately $30 per MW/day.

Exhibit 5-1 below looks at average per-megawatt annual revenues at various marginal unit costs using average revenue numbers from PJM's Market Monitoring Unit (MMU) in the PJM State of the Market Report – 2001. The energy revenues are derived by assuming each unit ran each hour the day-ahead LMP was at or above the unit's marginal cost. Ancillary Services (regulation and spinning reserve payments) were assumed to average $2,851 per MW/year, operating reserve revenue was $4,275 per MW/year, and capacity revenue was $36,700 per MW/year.

Exhibit 5-1
Per MW/Year Net Revenue by Marginal Cost
Based on 2001 Averages - PJM East



5.2 Unit Type Projections

PJM's generation fleet is comprised of many different units, operating at different cost levels due to the fuel cost and age and type of equipment. Exhibit 5-2 represents the current GEMSET estimate of stacking order of units in PJM East as of August 2002. Four composite generating unit types, representing about 70% of the installed capacity in PJM East and a wide range of operating costs, were chosen and the average net revenue numbers from PJM's report applied to each one. These were: coal steam turbines, nuclear steam turbines, natural gas combustion turbines, and distilled fuel oil combustion turbines. Exhibit 5-2 shows the types of installed units in PJM East, with average size and operating costs for each grouping by fuel source, stacked in cost order from low to high. The results of the unit-type revenue calculations are shown in table form as Exhibit 5-3, while the charts listed as Exhibit 5-4 and Exhibit 5-5 show stacked net revenue amounts and the percentages of revenue element for each selected type.

Exhibit 5-2
GEMSET Presumption of PJM East Generation Unit Stacking Order

Fuel Code	Fuel	Type Code	Unit Type	Avg Cost ($/MWH)	Avg kW	Ttl kW	Cum. kW	Percent of Ttl	Weighted Cost	Ttl Units
LFG	Landfill Gas	GT	Gas Turbine	$ 0.31	3	7	7	0.00%	$ 0.31	2
OBG	Other Biomass Gases	IC	Internal Combustion	$ 0.31	3	13	20	0.00%	$ 0.31	4
OBG	Other Biomass Gases	ST	Steam Turbine	$ 0.31	9	9	29	0.00%	$ 0.31	1
OBG	Other Biomass Gases	GT	Gas Turbine	$ 0.31	3.3	3.3	32.0	0.00%	$ 0.31	1
LFG	Landfill Gas	IC	Internal Combustion	$ 0.41	3	13	45	0.00%	$ 0.41	5
LFG	Landfill Gas	ST	Steam Turbine	$ 0.41	27	80	125	0.01%	$ 0.41	3
OG	Other Gas	ST	Steam Turbine	$ 0.41	11	21	146	0.01%	$ 0.41	2
BLQ	Black Liquor	ST	Steam Turbine	$ 2.55	42	42	188	0.02%	$ 2.55	1
MSW	Municipal Solid Waste	OT	Other	$ 2.55	30	60	248	0.02%	$ 2.55	2
MSW	Municipal Solid Waste	ST	Steam Turbine	$ 2.55	46	370	618	0.06%	$ 2.55	8
WH	Waste Heat (gas)	CA	CC Steam Part	$ 2.55	127	764	1,382	0.13%	$ 2.55	6
WAT	Water	HY	Hydraulic Turbine	$ 3.32	25	1,172	2,554	0.25%	$ 3.32	47
WAT	Water	OT	Other	$ 3.32	7	13	2,567	0.25%	$ 3.32	2
WAT	Water	PS	Hydro Pumped Storage	$ 3.32	125	1,749	4,316	0.42%	$ 3.32	14
WOC	Culm	ST	Steam Turbine	$ 5.53	62	372	4,688	0.46%	$ 5.52	6
WC	Waste Coal	ST	Steam Turbine	$ 6.44	55	166	4,854	0.47%	$ 6.37	3
WC	Waste Coal	OT	Other	$ 6.89	110	110	4,964	0.48%	$ 6.89	1
PC	Petroleum Coke	ST	Steam Turbine	$ 12.35	29	57	5,021	0.49%	$ 12.35	2
BIT	**Bituminous**	**ST**	**Steam Turbine**	**$ 15.47**	**290**	**19,430**	**24,451**	**2.38%**	**$ 14.80**	**67**
NUC	**Nuclear**	**ST**	**Steam Turbine**	**$ 15.45**	**1,025**	**13,328**	**37,779**	**3.67%**	**$ 15.44**	**13**
BIT	Bituminous	OT	Other	$ 17.54	68	479	38,258	3.72%	$ 17.03	7
BFG	Blast Furnace gas	ST	Steam Turbine	$ 20.18	152	152	38,410	3.73%	$ 20.18	1
NG	Natural Gas	CC	Combined Cycle	$ 28.45	165	495	38,905	3.78%	$ 28.32	3
NG	Natural Gas	CA	CC Steam Part	$ 28.60	147	147	39,052	3.79%	$ 28.60	1
WDS	Wood Solids	ST	Steam Turbine	$ 29.01	13	25	39,077	3.80%	$ 28.71	2
NG	Natural Gas	CT	CC Combustion Turbine	$ 34.68	179	1,964	41,041	3.99%	$ 33.39	11
RFO	Residual Fuel Oil	IC	Steam Turbine	$ 36.89	6	25	41,066	3.99%	$ 36.89	4
NG	Natural Gas	ST	Steam Turbine	$ 41.82	242	3,391	44,457	4.32%	$ 39.39	14
RFO	Residual Fuel Oil	ST	Steam Turbine	$ 45.04	206	4,541	48,998	4.76%	$ 41.11	22
NG	Natural Gas	CS	CC Single Shaft	$ 43.54	23	47	49,045	4.77%	$ 43.54	2
NG	**Natural Gas**	**GT**	**Gas Turbine**	**$ 51.49**	**83**	**5,215**	**54,260**	**5.27%**	**$ 49.26**	**63**
NG	Natural Gas	OT	Other	$ 55.10	54	917	55,177	5.36%	$ 54.56	17
NG	Natural Gas	IC	Internal Combustion	$ 57.85	12	12	55,189	5.36%	$ 57.85	1
DFO	Distillate Fuel Oil	IC	Internal Combustion	$ 58.02	2	130	55,319	5.37%	$ 57.87	55
DFO	Distillate Fuel Oil	ST	Steam Turbine	$ 63.40	275	550	55,869	5.43%	$ 63.40	2
DFO	Distillate Fuel Oil	CT	CC Combustion Turbine	$ 72.53	70	280	56,149	5.46%	$ 72.53	4
DFO	**Distillate Fuel Oil**	**GT**	**Gas Turbine**	**$ 79.77**	**33**	**5,022**	**61,171**	**5.94%**	**$ 75.13**	**152**
DFO	Distillate Fuel Oil	OT	Other	$ 77.59	16	16	61,187	5.94%	$ 77.59	1
KER	Kerosene	GT	Gas Turbine	$ 91.89	76	1,376	62,563	6.08%	$ 99.54	18

Legend	
Fuel Oil/Kerosene	Coal
Biomass/Landfill	Water
Natural Gas	Other

Bold denotes units used in revenue model

Exhibit 5-3
GEMSET Estimate Example of Select PJM Units Net Revenue – 2001

Bituminous Steam Turbine (31%)

Nominal Rating (MW)	290
Outage Rate	8.43%
Capacity Avail	266
Marginal Cost ($MWh)	$ 14.80
Revenue Source	
Ancillary Services (MW)	$ 2,851.00
Operating Reserves (MW)	$ 4,275.00
Capacity (MW-Day)	$ 95.34
Revenue	
Capacity Factor	92.5%
Hours Run	8,103
Spot Energy	$ 46,169,324
Capacity Revenue	$ 9,241,005
Ancillary Services	$ 826,790
Operating Reserves	$ 1,239,750
Total	**$ 57,476,869**

Nuclear (21%)

Nominal Rating (MW)	1,025
Outage Rate	8.43%
Capacity Avail	939
Marginal Cost ($MWh)	$ 15.44
Revenue Source	
Ancillary Services (MW)	$ 2,851.00
Operating Reserves (MW	$ 4,275.00
Capacity (MW-Day)	$ 95.34
Revenue	
Capacity Factor	89.5%
Hours Run	7,844
Spot Energy	$ 157,956,429
Capacity Revenue	$ 32,662,174
Ancillary Services	$ 2,922,275
Operating Reserves	$ 4,381,875
Total	**$ 197,922,753**

Natural Gas Turbine (8%)

Nominal Rating (MW)	83
Outage Rate	8.43%
Capacity Avail	76
Marginal Cost ($MWh)	$ 49.26
Revenue Source	
Ancillary Services (MW)	$ 2,851.00
Operating Reserves (MW)	$ 4,275.00
Capacity (MW-Day)	$ 95.34
Revenue	
Capacity Factor	13.1%
Hours Run	1,145
Spot Energy	$ 2,519,532
Capacity Revenue	$ 2,644,839
Ancillary Services	$ 236,633
Operating Reserves	$ 354,825
Total	**$ 5,755,829**

Fuel Oil Turbine (8%)

Nominal Rating (MW)	33
Outage Rate	8.43%
Capacity Avail	30
Marginal Cost ($MWh)	$ 75.13
Revenue Source	
Ancillary Services (MW)	$ 2,851.00
Operating Reserves (MW)	$ 4,275.00
Capacity (MW-Day)	$ 30.00
Revenue	
Capacity Factor	2.8%
Hours Run	246
Spot Energy	$ 523,053
Capacity Revenue	$ 330,888
Ancillary Services	$ 94,083
Operating Reserves	$ 141,075
Total	**$ 1,089,099**

Operating Reserve Hours are assumed to be run when not dispatched - 2001 average payment
Capacity is total available unforced capacity sold all year
Ancillary Services and operating reserves assumed to be at 2001 average - from PJM State of the Market report 2001
Energy is dispatched all hours at or above marginal cost - numbers are net of assumed cost

Exhibit 5-4
GEMSET Estimated Example of Select PJM Units Net Revenue – 2001

by Fuel Type
Based on PJM LMP 7/2001-6/2002

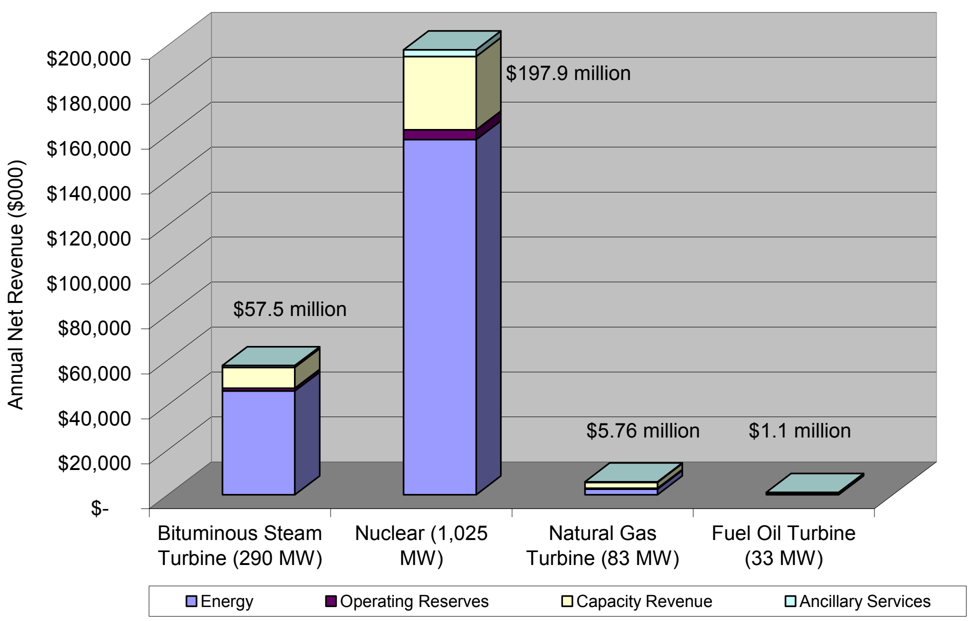
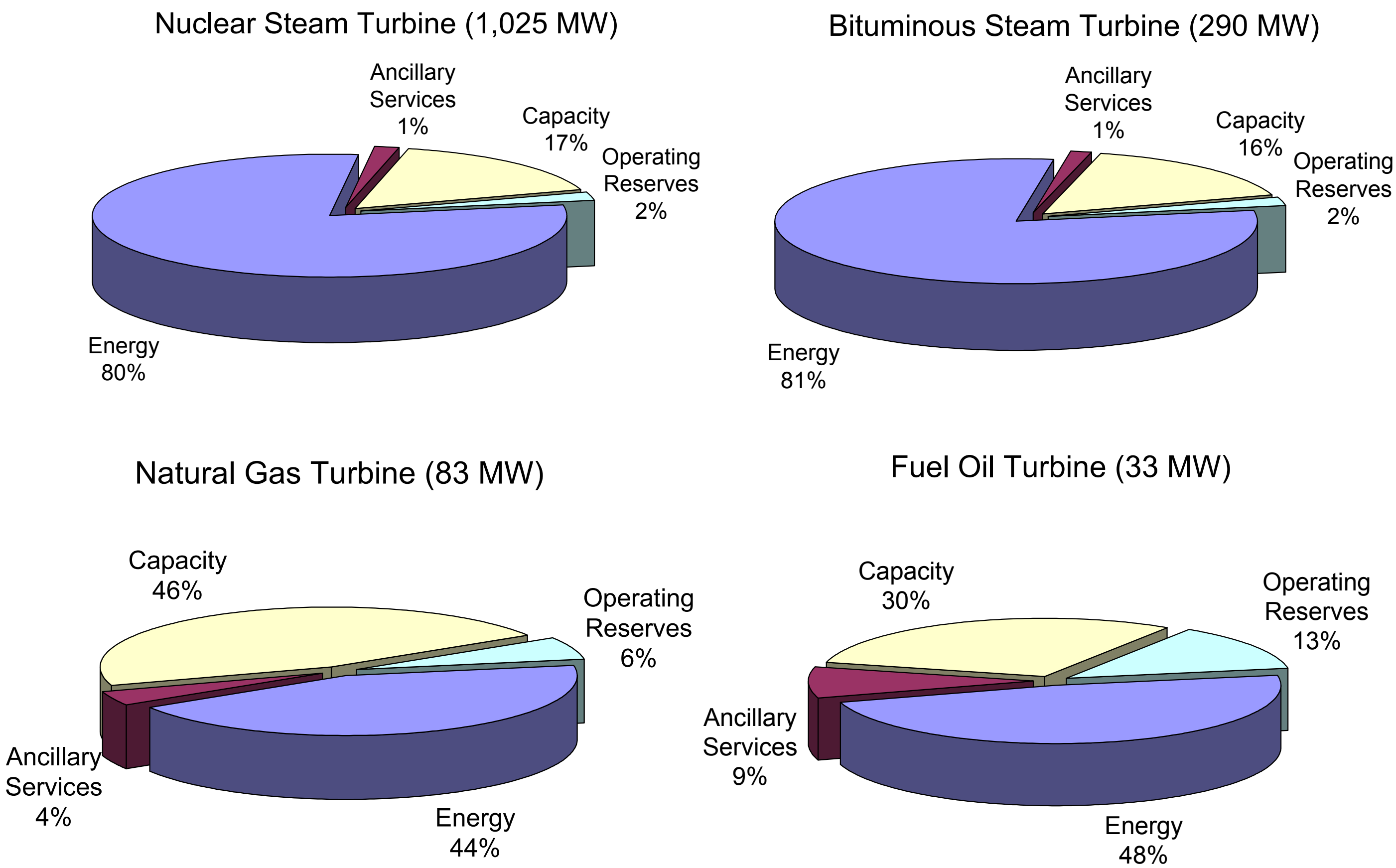


Exhibit 5-5
GEMSET Estimate Example of PJM Select Units Net Revenue Composition – 2001



In the above charts, the importance of capacity and operating reserves to the total net revenue of the higher-cost units is apparent and dramatic, at least at year 2001 levels. In the nuclear and coal-fired units, energy accounts for 80% or more of net revenue, while capacity represents only 16 or 17%. In the two high-cost configurations beneath them, capacity accounts for 30% to almost 50% of net revenue. *This revenue percentage was driven by an usually high capacity market. 2002 revenues will be significantly less for this component.*

6. The Future of PJM

PJM is currently undergoing a rapid evolution from a regional ISO to not only a multi-NERC-region RTO and wholesale market operator but also, based on the recent FERC Notice of Pending Rulemaking (NOPR) outlining a Standard Market Design, the model for an electrical system conceivably stretching from the Rocky Mountains to the Atlantic and from Canada to Mexico. The inclusion of Allegheny Power as PJM West and Dominion Power as PJM South has already driven discussions regarding the need to change PJM's name to something more representative of the expanding scope of its operations. The following section looks at some of the changes underway, and points to issues impacting longer-term wholesale electric pricing.

6.1 FERC'S Standard Market Design

On August 1, 2002, FERC issued a press release outlining its plan to create a nationwide set of rules to govern wholesale power markets and transmission line owners and operators. It said that many of the basic outlines of the plan are unchanged from one FERC has outlined in the past and has already heard comment on. "Clear rules and vigilant oversight under a uniform system will replace the obsolete patchwork that we have today," said FERC Chairman Pat Wood. A March Supreme Court decision upheld the FERC Commissioners' authority in a state-federal confrontation, paving the way for more aggressive action now.

The plan includes a national grid overseen by regional independent boards that would analyze load growth and generation needs and help determine what new power plants and transmission lines are needed, and where to locate them. The transmission network would be open to all generators under a single rate structure set by the Commission.

The proposed system would encourage long-term contracts and dampen potential price swings on the spot market. There also would be locational price differences reflecting transmission congestion, with the higher rates serving as an incentive for investors to build new lines and/or generation. FERC wants to put the plan into effect nationwide by September 30, 2004, and will be taking comments on the design for the next few months. The plan represents an expansion of FERC's Order No. 2000, which called for transmission owners to turn over their operations to an independent RTO in a timely manner.

6.1.1 MISO-PJM-SPP

Concurrent with and in accordance with FERC's desires is the proposed joining of the Midwest Independent Transmission System Operator, Inc. (MISO), PJM Interconnection, and Southwest Power Pool, Inc. (SPP). The intent of this union is to move toward effective implementation of a robust, non-discriminatory single energy market covering their collective regions. The result will be a common wholesale market with the ability to meet the needs of all customers and stakeholders utilizing the electric power grid in the 26 states, District of Columbia, and the Canadian province of Manitoba. The market will be developed through an open stakeholder process and will be designed to serve residents regardless of whether they reside in states with bundled or unbundled retail rates. According to the MISO-PJM-SPP website, critical design features will include:

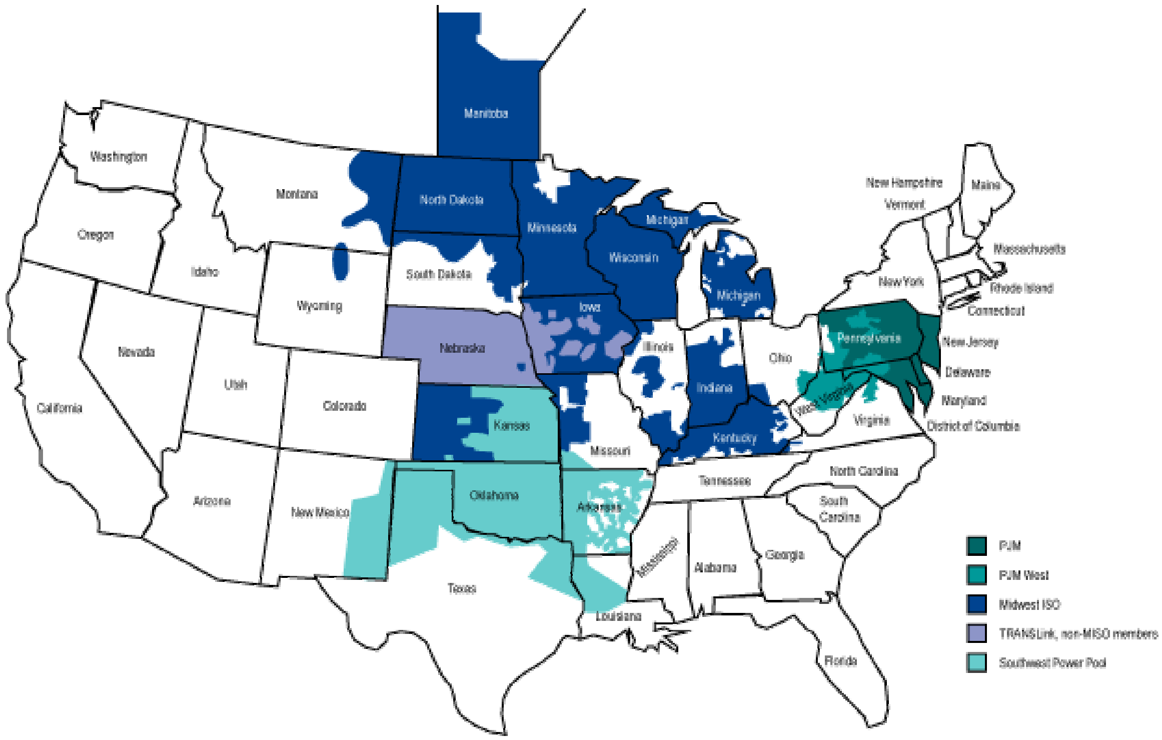
- Maintenance and improvement of system reliability
- Customer-oriented focus
- Clarity of market rules and operations
- Price transparency
- One-stop shopping for transmission service and energy products
- Simplicity for the user
- Open network architecture that provides for growth, redundancy, security, and flexibility for the future
- SAS 70 auditability and accountability to the customers
- Consistent and well-understood models that are aligned with the FERC vision for large, standardized markets
- Value from geographic, resource, and weather diversity

The actual administration of the market will be undertaken by MISO and PJM (SPP is currently merging with MISO) and will be designed to accommodate various business models including Independent Transmission Companies (ITCs), public power, municipal utilities, and joint action agencies. The scope of the proposed combined markets includes:

- 184,350 MW peak load
- 203,508 MW generating capacity

- 137,500 miles of transmission lines
- More than 300 members
- More than 30 million customers

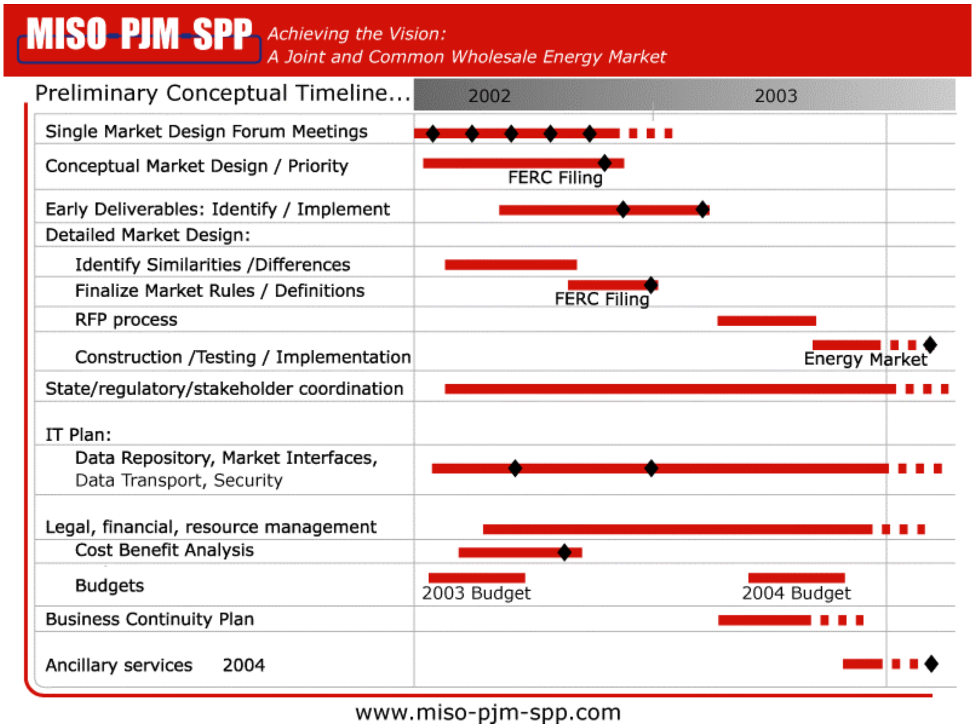
Exhibit 6-1
MISO-PJM-SPP Combined Service Territory



Source: MISO-PJM-SPP Website. www.miso-pjm-spp.com

The timeline for implementation is fluid but aggressive. At a meeting in Baltimore on August 22, 2002, more than 100 representatives from the three ISOs, regional utility companies, FERC, end-users, and interested parties met to resolve transmission issues. FERC's stated goal at that meeting was to reach a consensus on or before September 16, 2002. A conceptual timeline is shown in Exhibit 6-2.

Exhibit 6-2
MISO-PJM-SPP Conceptual Timeline



6.1.2 Dominion Virginia Power

On June 25, 2002 Dominion Virginia Power and PJM Interconnection LLC announced their agreement to have Dominion's 6,000 miles of transmission lines in Virginia and North Carolina operated by PJM. The Memo of Understanding (MOU) establishes the means by which Dominion will become a member of PJM's RTO. Under terms of the agreement, Dominion would establish PJM South, similar to PJM West. Both parties have 120 days to finalize specifics of the agreement, which went on to state that Dominion's assets would be fully integrated into PJM as soon as possible. The agreement is subject to FERC approval.

6.1.3 NYISO

PJM and the New York ISO (NYISO) announced an Interregional Coordination and Resolution Agreement effective March 15, 2002. The goal of the agreement is to resolve "seams" issues between the two control areas on an expedited basis. These occur when a difference in rules between neighboring electric markets causes problems with interregional trading. The agreement requires that a work plan be developed and quarterly reports issued to FERC, which will act as an arbiter for any disputes.

6.2 Looking Forward

Based on the evidence of PJM's market operations over the past 3 years, it would appear that there is a reasonable correlation between the cost of providing generation and both spot and forward prices. PJM's market transparency and conservative administration have resulted in highly liquid spot markets. There also appears to be ample generation online and in queue to ensure ample supply when compared to load growth through 2007. Thus, fuel cost is likely to remain the prime indicator of marginal cost over the short term.

6.2.1 Unresolved Issues

There remain important issues that could significantly impact the volatility of electric pricing in the future and whose resolution is not clear at the moment. Among these are:

- **Generation Fleet Diversity** – The vast majority of units recently added, under construction or in queue are combined cycle natural gas units, and the percentage of nuclear and coal baseload generation has not changed appreciably over the past few years. This means that, as load growth occurs, a higher percentage of hours will induce the gas units to be dispatched, forcing the average cost of electricity to track with that of natural gas. As was seen in 2001, natural gas prices can produce dramatic volatility, having then spiked to more than $10/MMBtu during the year, and averaging $5.14/MMBtu for the full year, compared with $2.82/MMBtu for the decade prior to that.

- **Long-Term Incentives for Construction** – A critical issue among those working on the Standard Market Design is that of providing adequate incentive to encourage the construction of new generation and transmission assets in time to avoid severe "short" capacity periods. New load comes on gradually, but generation comes on line in "chunks" of capacity. There is a danger under the current system that, by the time unambiguous price signals trigger a spate of new construction, the lag time required will create a period of high-priced and highly volatile electric pricing. There is also a danger that a preponderance of mid-merit or peaking units rather than baseload (nuclear, hydro, or coal) are likely to be built until and unless developers and financiers can feel more comfortable about making longer-term business investment decisions. If adequate market incentives are not provided, generation and transmission construction will be doomed to a boom-and-bust cycle.

- **Demand Side Response** – Too much generation available at a given time reduces the value of capacity, while too little drives LMPs and capacity higher. In order to fully realize the benefits of an open marketplace, the demand side of the equation will have to become more responsive. New metering technology and complex real-time dispatch systems will be needed. FERC's SMD NOPR recognizes the importance of this aspect of the marketplace, and is sponsoring dialogue between stakeholders today.

- **Capacity and Transmission** – Unlike energy, where the PJM methodology appears sustainable, significant issues surround both the capacity and transmission elements of electric costs at the wholesale level. There seems to be a need to develop greater present value for "first-in" generation and rewards for building transmission assets that go beyond Financial Transmission Rights. Among the incentives being discussed are capacity credits being issued in advance of construction for a number of years (with penalties for not completing construction) and withheld from older units presumed to have been paid off, and sharing of generation revenue for some period of time associated with improvements in the transmission system performed by an Independent Transmission Company.

- **Other Issues** – Other critical issues impacting future electric costs include:

  - Environmental legislation – renewable/pollution requirements
  - System load factor (baseload opportunity versus peaking requirements)
  - The nature of peaking technology (which will drive market highs)
  - The prospects for clean coal and/or nuclear re-emergence
  - The speed of development of a real-time energy marketplace
  - The nature and clarity of final Standard Market Design
  - Stability and reasonableness of state regulatory environment
  - National deregulation legislation and energy policy
  - Population growth
  - Development of liquid electric commodity and derivative forward markets
  - Siting issues
  - Labor relations
  - Economic growth
  - Concentration of ownership

  - Changes in transmission technology
  - The manner and means by which the transmission system is refurbished
  - Rate of generator retirement

6.2.2 Areas for Further Study

To perform a 20-year forward look at electric pricing, there is a need to:

- Understand and study the impact of the Standard Market Design on the future diversification of the generation fleet and interpret the kind of business environment it creates, especially as to whether it provides developers the ability to make better, long-term investment decisions, and what those decisions may in fact be.

- Study the natural gas storage and transportation system in tandem with that of electric generation and transmission, as the nature of this "energy backbone" may be the most critical driver of electric cost in the not-too-distant future.

- Analyze the impact of Demand Response initiatives and the impetus for creation of a real-time energy marketplace (RTEM). The speed of the realization of the RTEM will open the way for end-users to control their usage and soften the impact and duration of price spikes and "short" generation periods.

- Study the emerging retail electric industry. The rules that impact retail electric delivery are currently not in sync with the wholesale market. The tariffs in place move slowly, if at all, producing a divergence between retail costs and those faced at the wholesale level. This situation is being addressed in a variety of ways in deregulating states, but the rate and specific nature of this change will impact the number of market participants and appeal of Demand Response and other demand-side initiatives.

6.2.3 Conclusion

In conclusion, predicting the outlook for generation capacity and thus the long-term price implications for generation in the PJM region, and elsewhere in North America, is difficult at best. The way electric transactions operate, the size of the PJM market, and the revenue return prospects for generating companies are evolving rapidly as PJM grows, and as its competitive structure matures. However, the framework that is being constructed now by FERC with PJM as a model is striving to allow market forces to provide the incentives for new construction, as well as the means by which market power and extreme volatility can be limited. The issues are clear. The solutions will require much work over the next few years.

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Appendix A, PJM Fleet Stacking

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Exelon Generation Company, LLC	Pennsbury	GT	LFG	3000	3
Exelon Generation Company, LLC	Pennsbury	GT	LFG	3000	7
Ogden Energy Group Inc.	Gude Landfill	IC	OBG	1100	8
Ogden Energy Group Inc.	Gude Landfill	IC	OBG	1100	9
Public Service Electric&Gas Co	O'Brien	ST	OBG	9500	18
Public Service Electric&Gas Co	Kinsley	IC	OBG	3000	20
Bio-Energy Partners	Pottstown Landfill	GT	OBG	6600	26
Exelon Generation Company, LLC	Grand Central Landfill	IC	OBG	8500	34
Lebanon Methane Recovery Inc.	Lebanon	IC	LFG	1500	35
PEI Power Corporation	Archbald NUG	ST	LFG	19000	55
PPL Utilities	Amity Landfill	IC	LFG	1000	56
PPL Utilities	Keystone Landfill	IC	LFG	5000	61
PSEG Energy Resources and Trading LLC	Balefill Landfill	IC	LFG	3800	65
PSEG Energy Resources and Trading LLC	Kingsland Landfill	IC	LFG	1900	67
Atlantic City Electric Co	Mobil NUG	ST	OG	15000	78
Atlantic City Electric Co	Mobil NUG	ST	OG	15000	89
Exelon Generation Company, LLC	Fairless Hills	ST	LFG	30000	119
Exelon Generation Company, LLC	Fairless Hills	ST	LFG	30000	149
Conectiv Delmarva Generation Inc.	Hay Road	CA	WH	160000	324
First Energy / Metropolitan Edison Co	Lancaster Co RR NUG	OT	MSW	36000	354
First Energy / Metropolitan Edison Co	York County RR NUG	OT	MSW	36000	384
Ogden Energy Group Inc.	Union Co. Resource Recovery	ST	MSW	39000	423
Potomac Electric Power Co. PPA	Muni Solid Waste (MCRRF)	ST	MSW	60000	475
PPL Utilities	Harrisburg MSW	ST	MSW	5000	481
PSEG Fossil LLC	Bergen	CA	WH	287000	676
PSEG Fossil LLC	Burlington	CA	WH	44800	728
Public Service Electric&Gas Co	Essex	ST	MSW	70000	793
Public Service Electric&Gas Co	Wheelabrator	ST	MSW	42000	841
Reliant Energy Services Inc.	Gilbert	CA	WH	135000	945
Atlantic City Electric Co	DRMI	ST	MSW	90000	1,020
Constellation Power Source	Bresco NUG	ST	MSW	60240	1,077
Exelon Generation Company, LLC	Grays Ferry NUG	CA	WH	54400	1,109
Exelon Generation Company, LLC	MMLP NUG	ST	MSW	32216	1,137
Willamette Industries, Inc.	Penntech	ST	BLQ	60000	1,179
Williams Energy Marketing & Trading Co	Ironwood	CA	WH	206000	1,385
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	1,505
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	1,615
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	1,725
First Energy / Metropolitan Edison Co	York Haven	HY	WAT	19600	1,744
First Energy / Pennsylvania Electric Co	Conemaugh Dam NUG	OT	WAT	16500	1,752
First Energy / Pennsylvania Electric Co	Seneca	PS	WAT	198000	1,949
First Energy / Pennsylvania Electric Co	Seneca	PS	WAT	198000	2,159

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
First Energy / Pennsylvania Electric Co	Seneca	PS	WAT	32000	2,191
First Energy / Pennsylvania Electric Co	Youghiogheny NUG	OT	WAT	11000	2,196
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,206
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,217
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,227
PPL Holtwood, LLC	Holtwood	HY	WAT	500	2,227
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,237
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,247
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,257
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,268
PPL Holtwood, LLC	Holtwood	HY	WAT	10400	2,279
PPL Holtwood, LLC	Holtwood	HY	WAT	500	2,280
PPL Holtwood, LLC	Holtwood	HY	WAT	12000	2,291
PPL Holtwood, LLC	Holtwood	HY	WAT	12000	2,303
PPL Wallenpaupack, LLC	Wallenpaupack	HY	WAT	20000	2,325
PPL Wallenpaupack, LLC	Wallenpaupack	HY	WAT	20000	2,347
Public Service Electric&Gas Co	Great	HY	WAT	11000	2,358
Reliant Energy Services Inc.	Deep Creek	HY	WAT	9600	2,368
Reliant Energy Services Inc.	Deep Creek	HY	WAT	9600	2,377
Reliant Energy Services Inc.	Piney	HY	WAT	9600	2,386
Reliant Energy Services Inc.	Piney	HY	WAT	9600	2,395
Reliant Energy Services Inc.	Piney	HY	WAT	9600	2,405
Allegheny Electric Coop Inc	Raystown	HY	WAT	12000	2,417
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,453
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,489
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,525
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,561
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,597
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,633
Exelon Generation Company, LLC	Conowingo	HY	WAT	36000	2,669
Exelon Generation Company, LLC	Conowingo	HY	WAT	55620	2,734
Exelon Generation Company, LLC	Conowingo	HY	WAT	55620	2,799
Exelon Generation Company, LLC	Conowingo	HY	WAT	55620	2,864
Exelon Generation Company, LLC	Conowingo	HY	WAT	55620	2,929
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	3,039
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	3,149
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	3,269
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	3,379
Exelon Generation Company, LLC	Muddy Run	PS	WAT	100000	3,499
First Energy/Jersey Central Power&Light Co	Yards Creek	PS	WAT	151000	3,639
First Energy/Jersey Central Power&Light Co	Yards Creek	PS	WAT	151000	3,779
First Energy/Jersey Central Power&Light Co	Yards Creek	PS	WAT	151000	3,899
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	32000	3,931
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	2000	3,933
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	2000	3,935

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	37500	3,972
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	38500	4,011
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	37500	4,048
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	38500	4,087
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	37500	4,124
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	33000	4,157
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	32000	4,189
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	32000	4,221
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	33000	4,254
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	32000	4,286
Safe Harbor Water Power Corp	Safe Harbor	HY	WAT	32000	4,318
PPL Utilities	Gilberton Power	ST	WOC	79000	4,400
Sunbury Generation, L.L.C.	Sunbury	ST	WOC	75000	4,476
Sunbury Generation, L.L.C.	Sunbury	ST	WOC	75000	4,552
PPL Utilities	Northeast Power Co	ST	WOC	50000	4,604
PPL Utilities	Foster Wheeler	ST	WOC	40000	4,647
PPL Utilities	Frackville	ST	WOC	43000	4,690
Schuylkill Energy Resources Inc.	Schuylkill Energy	ST	WC	99242	4,778
WPS Westwood Generation LLC	Westwood NUG	ST	WC	36000	4,808
UGI Development Corporation	Hunlock Power Station	ST	WC	49998	4,856
PG&E Energy Trading - Power, L.P.	Northampton NUG	OT	WC	117000	4,966
Conectiv Delmarva Generation Inc.	Delaware City	ST	PC	27500	4,995
Conectiv Delmarva Generation Inc.	Delaware City	ST	PC	27500	5,023
PPL Montour, LLC	Montour	ST	BIT	819000	5,789
Mirant Potomac River, LLC	Morgantown	ST	BIT	626000	6,413
PPL Brunner Island, LLC	Brunner Island	ST	BIT	405000	6,803
PSEG Fossil LLC	Mercer	ST	BIT	326400	7,128
Mirant Potomac River, LLC	Morgantown	ST	BIT	626000	7,748
PPL Brunner Island, LLC	Brunner Island	ST	BIT	790400	8,493
PPL Montour, LLC	Montour	ST	BIT	17200	8,508
PPL Montour, LLC	Montour	ST	BIT	805500	9,267
Constellation Power Source	Herbert A Wagner	ST	BIT	359041	9,599
Reliant Energy Services Inc.	Conemaugh	ST	BIT	936000	10,449
Reliant Energy Services Inc.	Conemaugh	ST	BIT	936000	11,299
Mirant Potomac River, LLC	Chalk Point	ST	BIT	364000	11,642
NRG Power Marketing, Inc.	Indian River	ST	BIT	176800	11,807
Mirant Potomac River, LLC	Dickerson	ST	BIT	196000	11,989
Mirant Potomac River, LLC	Chalk Point	ST	BIT	364000	12,330
PPL Brunner Island, LLC	Brunner Island	ST	BIT	363330	12,664
Mirant Potomac River, LLC	Dickerson	ST	BIT	196000	12,846
PSEG Fossil LLC	Mercer	ST	BIT	326400	13,171
Edison Mission Marketing and Trading, Inc.	Homer City	ST	BIT	660000	13,785
Edison Mission Marketing and Trading, Inc.	Homer City	ST	BIT	660000	14,405
PSEG Fossil LLC	Hudson	ST	BIT	659000	15,025
Reliant Energy Services Inc.	Keystone	ST	BIT	936000	15,875

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Reliant Energy Services Inc.	Keystone	ST	BIT	936000	16,725
Mirant Potomac River, LLC	Dickerson	ST	BIT	196000	16,907
Mirant Potomac River, LLC	Potomac River	ST	BIT	110000	17,009
Mirant Potomac River, LLC	Potomac River	ST	BIT	110000	17,111
Mirant Potomac River, LLC	Potomac River	ST	BIT	110000	17,213
Conectiv Delmarva Generation Inc.	Edge Moor	ST	BIT	176800	17,387
Edison Mission Marketing and Trading, Inc.	Homer City	ST	BIT	692000	18,037
NRG Power Marketing, Inc.	Indian River	ST	BIT	81600	18,128
Atlantic City Electric Co	CCLP NUG	ST	BIT	245000	18,373
Atlantic City Electric Co	B L England	ST	BIT	136000	18,502
Atlantic City Electric Co	B L England	ST	BIT	163200	18,657
Exelon Generation Company, LLC	Eddystone	ST	BIT	353600	18,968
Atlantic City Electric Co	Logan (KCS) (Keystone)	ST	BIT	285000	19,187
Reliant Energy Services Inc.	Seward	ST	BIT	156200	19,324
Reliant Energy Services Inc.	Shawville	ST	BIT	187500	19,504
Reliant Energy Services Inc.	Shawville	ST	BIT	187500	19,684
Constellation Power Source	Brandon Shores	ST	BIT	685080	20,350
AmerGen Energy Company, L.L.C.	Oyster Creek	ST	NUC	640700	20,987
Constellation Power Source	Herbert A Wagner	ST	BIT	136000	21,122
Exelon Generation Company, LLC	Eddystone	ST	BIT	353600	21,410
Exelon Generation Company, LLC	Peach Bottom	ST	NUC	1152000	22,529
PPL Susquehanna, LLC	Susquehanna	ST	NUC	1152000	23,640
Constellation Power Source	Brandon Shores	ST	BIT	685080	24,306
NRG Power Marketing, Inc.	Indian River	ST	BIT	81600	24,397
PPL Susquehanna, LLC	Susquehanna	ST	NUC	1152000	25,504
Exelon Generation Company, LLC	Limerick	ST	NUC	1138473	26,702
Exelon Generation Company, LLC	Peach Bottom	ST	NUC	1152000	27,821
Exelon Generation Company, LLC	Limerick	ST	NUC	1138473	29,003
PSEG Nuclear LLC	Salem	ST	NUC	1170000	30,113
PSEG Nuclear LLC	Salem	ST	NUC	1170000	31,224
PSEG Nuclear LLC	Hope	ST	NUC	1170000	32,318
Constellation Power Source	Calvert Cliffs	ST	NUC	918000	33,183
Constellation Power Source	Calvert Cliffs	ST	NUC	910710	34,048
Constellation Power Source	C P Crane	ST	BIT	209440	34,243
Constellation Power Source	C P Crane	ST	BIT	190400	34,433
AmerGen Energy Company, L.L.C.	Three Mile Island	ST	NUC	837000	35,243
Reliant Energy Services Inc.	Titus	ST	BIT	75000	35,326
NRG Power Marketing, Inc.	Indian River	ST	BIT	442400	35,746
Atlantic City Electric Co	Deepwater	ST	BIT	73500	35,827
Conectiv Delmarva Generation Inc.	Edge Moor	ST	BIT	75000	35,913
Exelon Generation Company, LLC	Cromby	ST	BIT	187500	36,060
Reliant Energy Services Inc.	Portland	ST	BIT	255000	36,303
Reliant Energy Services Inc.	Titus	ST	BIT	75000	36,386
Sunbury Generation, L.L.C.	Sunbury Generation, L.L.C.	ST	BIT	156250	36,520
Reliant Energy Services Inc.	Shawville	ST	BIT	125000	36,648

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Reliant Energy Services Inc.	Shawville	ST	BIT	125000	36,778
Reliant Energy Services Inc.	Titus	ST	BIT	75000	36,861
First Energy / Pennsylvania Electric Co	Colver NUG	OT	BIT	102000	36,971
Reliant Energy Services Inc.	Portland	ST	BIT	171700	37,129
First Energy / Pennsylvania Electric Co	Cambria NUG	OT	BIT	90000	37,217
PPL Martins Creek, LLC	Martins Creek	ST	BIT	156250	37,367
First Energy / Pennsylvania Electric Co	Scrubgrass NUG	OT	BIT	90000	37,452
PPL Martins Creek, LLC	Martins Creek	ST	BIT	156250	37,602
First Energy / Metropolitan Edison Co	Panther Creek NUG	OT	BIT	93000	37,682
Vineland City of	Howard Down	ST	BIT	25000	37,705
Sunbury Generation, L.L.C.	Sunbury	ST	BIT	103530	37,808
Mirant Potomac River, LLC	Potomac River	ST	BIT	92000	37,896
Mirant Potomac River, LLC	Potomac River	ST	BIT	92000	37,984
First Energy / Pennsylvania Electric Co	Ebensburg NUG	OT	BIT	55000	38,034
First Energy / Metropolitan Edison Co	P. H. Glatfelter NUG	OT	BIT	67300	38,069
Reliant Energy Services Inc.	Seward	ST	BIT	62029	38,131
First Energy / Pennsylvania Electric Co	Piney Creek NUG	OT	BIT	34000	38,162
Reliant Energy Services Inc.	Warren	ST	BIT	42300	38,203
Reliant Energy Services Inc.	Warren	ST	BIT	42300	38,244
Bethlehem Steel	Bethlehem Steel (Pennwood)	ST	BFG	110000	38,396
Dover City Of	General Foods	ST	BIT	18000	38,412
Potomac Electric Power Co. PPA	Panda	GT	NG	230000	38,642
Williams Energy Marketing & Trading Co	Ironwood	CT	NG	222000	38,864
Williams Energy Marketing & Trading Co	Ironwood	CT	NG	222000	39,086
Public Service Electric&Gas Co	Eagle	CC	NG	230000	39,306
PSEG Fossil LLC	Burlington	GT	NG	168000	39,506
PPL Utilities	Viking Energy	ST	WDS	17000	39,523
El Paso Merchant Energy	Camden (Cogen Tech)	CC	NG	160000	39,682
El Paso Merchant Energy	Newark Bay	CA	NG	130000	39,829
Exelon Generation Company, LLC	Grays Ferry NUG	CT	NG	103500	39,947
Pedricktown Cogeneration Limited Partnership	Pedricktown (PCLP)	CC	NG	120000	40,063
PPL Utilities	Koppers Co.	ST	WDS	7000	40,071
PSEG Fossil LLC	Bergen	CT	NG	488000	40,551
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	144000	40,667
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	144000	40,783
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	144000	40,899
El Paso Merchant Energy	Bayonne Cogen Tech	GT	NG	165000	41,057
PSEG Fossil LLC	Burlington	CT	NG	179000	41,265
Conectiv Delmarva Generation Inc.	Edge Moor	ST	RFO	446000	41,710
Constellation Power Source	Perryman	GT	NG	191700	41,883
Easton Utilities Comm	Easton 2	IC	RFO	6300	41,890
Easton Utilities Comm	Easton 2	IC	RFO	6300	41,896
PPL Martins Creek, LLC	Martins Creek	ST	NG	850500	42,716
PPL Martins Creek, LLC	Martins Creek	ST	NG	850500	43,566
Easton Utilities Comm	Easton 2	IC	RFO	6250	43,572

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Easton Utilities Comm	Easton 2	IC	RFO	6250	43,579
Exelon Generation Company, LLC	Cromby	ST	NG	230000	43,790
PSEG Fossil LLC	Kearny	ST	RFO	147000	43,940
Mirant Potomac River, LLC	SMECo	GT	NG	94000	44,033
PSEG Fossil LLC	Kearny	ST	RFO	147000	44,183
PSEG Fossil LLC	Linden	ST	RFO	259722	44,433
Exelon Generation Company, LLC	Delaware	ST	RFO	156250	44,561
PSEG Fossil LLC	Bergen	GT	NG	18594	44,585
PSEG Fossil LLC	Sewaren	ST	NG	119000	44,712
Atlantic City Electric Co	B L England	ST	RFO	176400	44,872
Williams Energy Marketing & Trading Co	Hazelton NUG	GT	NG	63000	44,935
Reliant Energy Services Inc.	Gilbert	GT	DFO	161000	45,118
Mirant Potomac River, LLC	Dickerson H	GT	NG	163000	45,285
Mirant Potomac River, LLC	Dickerson H	GT	NG	163000	45,452
PSEG Fossil LLC	Linden	ST	RFO	259722	45,632
PSEG Fossil LLC	Hudson	ST	NG	454780	46,037
Exelon Generation Company, LLC	Schuylkill	ST	RFO	190400	46,212
Reliant Energy Services Inc.	Portland	GT	DFO	156000	46,365
Mirant Potomac River, LLC	Chalk Point	ST	RFO	659000	46,977
PSEG Fossil LLC	Essex	GT	NG	93600	47,070
Constellation Power Source	Handsome Lake	GT	NG	57000	47,120
Constellation Power Source	Handsome Lake	GT	NG	57000	47,170
Constellation Power Source	Handsome Lake	GT	NG	57000	47,220
Constellation Power Source	Handsome Lake	GT	NG	57000	47,270
Constellation Power Source	Handsome Lake	GT	NG	57000	47,320
FPL Energy Power Marketing, Inc.	MH 50	GT	NG	50500	47,370
Atlantic City Electric Co	Deepwater	ST	NG	81600	47,457
Mirant Potomac River, LLC	Chalk Point	ST	RFO	659000	48,069
NRG Power Marketing, Inc.	Kent	GT	NG	50000	48,113
NRG Power Marketing, Inc.	Kent	GT	NG	50000	48,157
UGI Development Corporation	Hunlock Power Station	GT	NG	44000	48,201
PEI Power II, LLC	Archbald NUG	GT	NG	45000	48,244
Mirant Potomac River, LLC	Chalk Point	GT	NG	125000	48,364
Mirant Potomac River, LLC	Chalk Point	GT	NG	125000	48,484
PSEG Fossil LLC	Sewaren	ST	NG	108000	48,593
NRG Power Marketing, Inc.	Vienna	ST	RFO	162000	48,749
Exelon Generation Company, LLC	Eddystone	ST	RFO	391000	49,129
Constellation Power Source	Herbert A Wagner	ST	RFO	414720	49,544
PSEG Fossil LLC	Linden	GT	NG	96135	49,636
Exelon Generation Company, LLC	Eddystone	ST	RFO	391000	50,016
PSEG Fossil LLC	Sewaren	ST	NG	103000	50,123
PSEG Fossil LLC	Linden	GT	NG	96135	50,215
Dover City Of	McKee Run	ST	RFO	113600	50,317
Constellation Power Source	Riverside	ST	NG	72250	50,396
Vineland City of	VCLP NUG	CS	NG	23250	50,420

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Vineland City of	VCLP NUG	CS	NG	23250	50,443
Constellation Power Source	Gould Street	ST	NG	103500	50,547
Atlantic City Electric Co	Mobil NUG	GT	NG	27000	50,569
PSEG Fossil LLC	Edison	GT	NG	167400	50,763
Constellation Power Source	Herbert A Wagner	ST	NG	132813	50,901
Reliant Energy Services Inc.	Sayreville	ST	NG	122500	51,018
Mirant Potomac River, LLC	Chalk Point	GT	NG	103000	51,117
Mirant Potomac River, LLC	Chalk Point	GT	NG	103000	51,216
Exelon Generation Company, LLC	Delaware	ST	RFO	156250	51,344
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	103500	51,466
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	103500	51,588
Conectiv Delmarva Generation Inc.	Hay Road	CT	NG	103500	51,710
Hess Energy Inc.	Paxton Creek Cogen	GT	NG	12000	51,722
PSEG Fossil LLC	Sewaren	ST	NG	100000	51,842
Reliant Energy Services Inc.	Sayreville	ST	NG	125000	51,959
Conectiv Atlantic Generation Inc.	Mickleton	GT	NG	71200	52,038
First Energy/Jersey Central Power&Light Co	MCRC (Monmouth)	GT	NG	7000	52,045
Constellation Power Source	Riverside	GT	NG	121500	52,178
Conectiv Atlantic Generation Inc.	Cumberland	GT	NG	96000	52,274
First Energy/Jersey Central Power&Light Co	Forked River	GT	NG	38400	52,316
First Energy/Jersey Central Power&Light Co	Forked River	GT	NG	38400	52,360
First Energy/Pennsylvania Electric Co	Lakeview NUG	GT	NG	9150	52,365
First Energy/Jersey Central Power&Light Co	Manchester NUG	GT	NG	6000	52,370
Conectiv Atlantic Generation Inc.	Sherman Avenue	GT	NG	109640	52,466
Atlantic City Electric Co	Deepwater	GT	NG	18600	52,490
Easton Utilities Comm	Easton	IC	DFO	1500	52,491
Easton Utilities Comm	Easton	IC	DFO	1500	52,493
Easton Utilities Comm	Easton 2	IC	DFO	1500	52,494
Easton Utilities Comm	Easton 2	IC	DFO	1500	52,496
Easton Utilities Comm	Easton	IC	DFO	4120	52,500
Vineland City of	Howard Down	ST	RFO	12500	52,511
Conectiv Delmarva Generation Inc.	Delaware City	ST	RFO	88235	52,559
Easton Utilities Comm	Easton	IC	DFO	5620	52,565
Easton Utilities Comm	Easton	IC	DFO	5620	52,570
Vineland City of	Howard Down	ST	RFO	16500	52,587
PSEG Fossil LLC	Essex	GT	NG	167400	52,799
PSEG Fossil LLC	Edison	GT	NG	167200	52,993
Curtis Papers	Curtis Papers IPP	OT	NG	5000	52,998
First Energy / Metropolitan Edison Co	Composite (ME) NUG	OT	NG	1000	52,999
First Energy / Metropolitan Edison Co	Modern Landfill	OT	NG	8000	53,007
First Energy / Pennsylvania Electric Co	PN Composite NUG	OT	NG	7000	53,014
Hess Energy Inc.	Cat Tractor NUG	OT	NG	66000	53,073
Public Service Electric&Gas Co	Starmark	OT	NG	3000	53,076
First Energy/Jersey Central Power&Light Co	Camden County RR NUG	OT	NG	23500	53,099
First Energy/Jersey Central Power&Light Co	Composite (JC) NUG	OT	NG	12000	53,111

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
First Energy/Jersey Central Power&Light Co	Gloucester Co RR NUG	OT	NG	13000	53,123
First Energy/Jersey Central Power&Light Co	Kenilworth NUG	OT	NG	25000	53,138
First Energy/Jersey Central Power&Light Co	Lakewood	OT	NG	236000	53,400
First Energy/Jersey Central Power&Light Co	Marcal Paper NUG	OT	NG	65000	53,447
First Energy/Jersey Central Power&Light Co	Newark Boxboard NUG	OT	NG	57000	53,499
First Energy/Jersey Central Power&Light Co	Parlin Nug	OT	NG	132000	53,613
First Energy/Jersey Central Power&Light Co	South River NUG	OT	NG	290000	53,873
First Energy/Jersey Central Power&Light Co	Warren County RR NUG	OT	NG	10000	53,883
PSEG Fossil LLC	Essex	GT	NG	167400	54,095
Seaford City of	Seaford	IC	DFO	2000	54,097
Easton Utilities Comm	Easton	IC	DFO	3000	54,100
Conectiv Atlantic Generation Inc.	Carlls Corner	GT	NG	41900	54,143
Lewes City of	Lewes	IC	DFO	1000	54,144
Lewes City of	Lewes	IC	DFO	1000	54,145
Easton Utilities Comm	Easton	IC	DFO	3800	54,148
Reliant Energy Services Inc.	Blossburg	GT	NG	23600	54,174
Conectiv Atlantic Generation Inc.	Carlls Corner	GT	NG	41900	54,217
PPL Brunner Island, LLC	Brunner Island	IC	DFO	2750	54,220
PPL Brunner Island, LLC	Brunner Island	IC	DFO	2750	54,223
PPL Brunner Island, LLC	Brunner Island	IC	DFO	2750	54,226
Seaford City of	Seaford	IC	DFO	1100	54,227
Easton Utilities Comm	Easton	IC	DFO	3500	54,230
PSEG Fossil LLC	Essex	GT	NG	167400	54,424
Vineland City of	Howard Down	ST	RFO	7500	54,432
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	54,491
PSEG Fossil LLC	Edison	GT	NG	167400	54,685
Easton Utilities Comm	Easton	IC	DFO	2500	54,687
Easton Utilities Comm	Easton	IC	DFO	2500	54,689
Constellation Power Source	Westport	GT	NG	121500	54,821
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,823
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,825
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,827
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,829
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,831
Conectiv Delmarva Generation Inc.	Bayview	IC	DFO	2000	54,833
Atlantic City Electric Co	B L England	IC	DFO	2000	54,835
Public Service Electric&Gas Co	Trenton	IC	NG	12000	54,847
Exelon Generation Company, LLC	Schuylkill	IC	DFO	2750	54,850
Exelon Generation Company, LLC	Cromby	IC	DFO	2750	54,853
Exelon Generation Company, LLC	Delaware	IC	DFO	2750	54,855
Atlantic City Electric Co	B L England	IC	DFO	2000	54,857
PPL Martins Creek, LLC	Martins Creek	IC	DFO	2750	54,860
PPL Martins Creek, LLC	Martins Creek	IC	DFO	2750	54,862
Constellation Power Source	Notch Cliff	GT	NG	18000	54,879
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	54,938

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Constellation Power Source	Notch Cliff	GT	NG	18000	54,955
Reliant Energy Services Inc.	Shawville	IC	DFO	2000	54,957
Reliant Energy Services Inc.	Shawville	IC	DFO	2000	54,959
Reliant Energy Services Inc.	Shawville	IC	DFO	2000	54,961
Conectiv Delmarva Generation Inc.	Crisfield	IC	DFO	2850	54,964
Conectiv Delmarva Generation Inc.	Crisfield	IC	DFO	2850	54,966
Conectiv Delmarva Generation Inc.	Crisfield	IC	DFO	2850	54,969
Conectiv Delmarva Generation Inc.	Crisfield	IC	DFO	2850	54,971
Constellation Power Source	Notch Cliff	GT	NG	18000	54,988
Seaford City of	Seaford	IC	DFO	1100	54,990
Constellation Power Source	Notch Cliff	GT	NG	18000	55,007
Atlantic City Electric Co	B L England	IC	DFO	2000	55,009
Constellation Power Source	Notch Cliff	GT	NG	18000	55,026
Constellation Power Source	Notch Cliff	GT	NG	18000	55,043
Constellation Power Source	Notch Cliff	GT	NG	18000	55,060
Constellation Power Source	Notch Cliff	GT	NG	18000	55,077
PSEG Nuclear LLC	Salem	GT	DFO	41850	55,123
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,169
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,214
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,259
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,303
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,347
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,391
Commonwealth Chesapeake Company LLC	Chesapeake	GT	DFO	57500	55,435
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	55,494
Sunbury Generation, L.L.C.	Sunbury Generation, L.L.C.	IC	DFO	2750	55,497
Sunbury Generation, L.L.C.	Sunbury Generation, L.L.C.	IC	DFO	2750	55,500
PSEG Fossil LLC	Kearny	GT	NG	18594	55,524
PSEG Fossil LLC	Kearny	GT	NG	146250	55,683
PSEG Fossil LLC	Kearny	GT	NG	146250	55,842
Dover City Of	McKee Run	ST	RFO	18800	55,859
Dover City Of	McKee Run	ST	RFO	18800	55,876
Seaford City of	Seaford	IC	DFO	1400	55,877
Seaford City of	Seaford	IC	DFO	1400	55,878
Potomac Power Resources Inc.	Benning	ST	DFO	290000	56,153
Atlantic City Electric Co	B L England	IC	DFO	2000	56,155
Dover City Of	Van Sant Station	GT	DFO	37400	56,195
Potomac Power Resources Inc.	Benning	ST	DFO	290000	56,470
Reliant Energy Services Inc.	Conemaugh	IC	DFO	2800	56,473
Reliant Energy Services Inc.	Conemaugh	IC	DFO	2800	56,476
Reliant Energy Services Inc.	Conemaugh	IC	DFO	2800	56,478
Reliant Energy Services Inc.	Conemaugh	IC	DFO	2800	56,481
Reliant Energy Services Inc.	Keystone	IC	DFO	2800	56,484
Reliant Energy Services Inc.	Keystone	IC	DFO	2800	56,486
Reliant Energy Services Inc.	Keystone	IC	DFO	2800	56,489

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Reliant Energy Services Inc.	Keystone	IC	DFO	2800	56,492
Mirant Potomac River, LLC	Morgantown	GT	DFO	65000	56,557
Mirant Potomac River, LLC	Morgantown	GT	DFO	65000	56,622
Mirant Potomac River, LLC	Morgantown	GT	DFO	65000	56,687
Mirant Potomac River, LLC	Morgantown	GT	DFO	65000	56,752
Seaford City of	Seaford	IC	DFO	800	56,753
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	56,817
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	56,881
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	56,945
Exelon Generation Company, LLC	Richmond	GT	DFO	65889	57,011
Exelon Generation Company, LLC	Richmond	GT	DFO	65889	57,077
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	57,141
Exelon Generation Company, LLC	Croydon	GT	DFO	68300	57,205
Conectiv Delmarva Generation Inc.	Delaware City	GT	NG	107500	57,255
Reliant Energy Services Inc.	Warren	GT	DFO	53100	57,334
Reliant Energy Services Inc.	Wayne	GT	DFO	53100	57,410
Mirant Potomac River, LLC	Chalk Point	GT	DFO	16000	57,428
Constellation Power Source	Perryman	GT	DFO	53125	57,489
Constellation Power Source	Riverside	GT	DFO	25000	57,514
First Energy/Jersey Central Power&Light Co	Riegel Paper NUG	OT	NG	23800	57,541
Reliant Energy Services Inc.	Gilbert	CT	DFO	53700	57,611
Reliant Energy Services Inc.	Gilbert	CT	DFO	53700	57,681
Reliant Energy Services Inc.	Gilbert	CT	DFO	53700	57,751
Reliant Energy Services Inc.	Gilbert	CT	DFO	53700	57,821
Constellation Power Source	Perryman	GT	DFO	53125	57,882
Exelon Generation Company, LLC	Schuylkill	GT	DFO	21250	57,902
Exelon Generation Company, LLC	Delaware	GT	DFO	21250	57,922
Exelon Generation Company, LLC	Eddystone	GT	DFO	21250	57,942
Exelon Generation Company, LLC	Eddystone	GT	DFO	21250	57,962
Exelon Generation Company, LLC	Falls	GT	DFO	21250	57,982
Exelon Generation Company, LLC	Falls	GT	DFO	21250	58,002
Exelon Generation Company, LLC	Falls	GT	DFO	21250	58,022
Exelon Generation Company, LLC	Moser	GT	DFO	21250	58,042
Exelon Generation Company, LLC	Moser	GT	DFO	21250	58,062
Exelon Generation Company, LLC	Moser	GT	DFO	21250	58,082
Conectiv Delmarva Generation Inc.	Tasley	GT	DFO	27000	58,115
Constellation Power Source	Perryman	GT	DFO	53125	58,176
Constellation Power Source	Perryman	GT	DFO	53125	58,237
PPL Martins Creek, LLC	Fishbach	GT	DFO	18590	58,255
PPL Martins Creek, LLC	Fishbach	GT	DFO	18590	58,273
PPL Martins Creek, LLC	Lock Haven	GT	DFO	18590	58,291
PPL Martins Creek, LLC	West Shore	GT	DFO	18590	58,309
PPL Martins Creek, LLC	West Shore	GT	DFO	18590	58,327
Exelon Generation Company, LLC	Schuylkill	GT	DFO	18600	58,345
Exelon Generation Company, LLC	Southwark	GT	DFO	18600	58,363

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Exelon Generation Company, LLC	Southwark	GT	DFO	18600	58,381
Exelon Generation Company, LLC	Southwark	GT	DFO	18600	58,399
Exelon Generation Company, LLC	Southwark	GT	DFO	18600	58,417
Exelon Generation Company, LLC	Chester	GT	DFO	18600	58,435
Exelon Generation Company, LLC	Chester	GT	DFO	18600	58,453
Exelon Generation Company, LLC	Delaware	GT	DFO	18600	58,471
Exelon Generation Company, LLC	Delaware	GT	DFO	18600	58,489
Exelon Generation Company, LLC	Delaware	GT	DFO	18600	58,507
Exelon Generation Company, LLC	Eddystone	GT	DFO	18600	58,525
Exelon Generation Company, LLC	Eddystone	GT	DFO	18600	58,543
PPL Martins Creek, LLC	Martins Creek	GT	DFO	24000	58,567
Conectiv Delmarva Generation Inc.	Christiana	GT	DFO	26640	58,592
Conectiv Delmarva Generation Inc.	Christiana	GT	DFO	28000	58,617
PPL Martins Creek, LLC	Martins Creek	GT	DFO	24000	58,641
PPL Martins Creek, LLC	Martins Creek	GT	DFO	24000	58,665
PPL Martins Creek, LLC	Martins Creek	GT	DFO	24000	58,689
Sunbury Generation, L.L.C.	Sunbury Generation, L.L.C.	GT	DFO	24000	58,713
Sunbury Generation, L.L.C.	Sunbury Generation, L.L.C.	GT	DFO	24000	58,737
NRG Power Marketing, Inc.	Indian River	GT	DFO	18600	58,758
Conectiv Atlantic Generation Inc.	Middle	GT	KER	21200	58,781
First Energy / Pennsylvania Electric Co	IUP NUG	OT	DFO	24300	58,797
PPL Martins Creek, LLC	Allentown	GT	DFO	18000	58,815
PPL Martins Creek, LLC	Allentown	GT	DFO	18000	58,833
PPL Martins Creek, LLC	Allentown	GT	DFO	18000	58,851
PPL Martins Creek, LLC	Allentown	GT	DFO	18000	58,869
PPL Martins Creek, LLC	Harrisburg	GT	DFO	18000	58,887
PPL Martins Creek, LLC	Harrisburg	GT	DFO	18000	58,905
PPL Martins Creek, LLC	Harrisburg	GT	DFO	18000	58,923
PPL Martins Creek, LLC	Harrisburg	GT	DFO	18000	58,941
PPL Martins Creek, LLC	Harwood	GT	DFO	18000	58,959
PPL Martins Creek, LLC	Harwood	GT	DFO	18000	58,977
PPL Martins Creek, LLC	Jenkins	GT	DFO	18000	58,995
PPL Martins Creek, LLC	Jenkins	GT	DFO	18000	59,013
PPL Martins Creek, LLC	Williamsport	GT	DFO	18000	59,031
PPL Martins Creek, LLC	Williamsport	GT	DFO	18000	59,049
Mirant Potomac River, LLC	Dickerson	GT	DFO	16000	59,062
Mirant Potomac River, LLC	Morgantown	GT	DFO	18000	59,082
Mirant Potomac River, LLC	Morgantown	GT	DFO	18000	59,102
Mirant Potomac River, LLC	Chalk Point	GT	DFO	35000	59,137
Conectiv Delmarva Generation Inc.	Delaware City	GT	DFO	18594	59,155
Exelon Generation Company, LLC	Chester	GT	DFO	18600	59,173
NRG Power Marketing, Inc.	Vienna	GT	DFO	18600	59,194
Constellation Power Source	Philadelphia Road	GT	DFO	20700	59,211
Conectiv Atlantic Generation Inc.	Middle	GT	KER	21200	59,234
Conectiv Atlantic Generation Inc.	Missouri Avenue	GT	KER	18600	59,258

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Conectiv Atlantic Generation Inc.	Missouri Avenue	GT	KER	18600	59,282
Constellation Power Source	Philadelphia Road	GT	DFO	20700	59,299
Conectiv Atlantic Generation Inc.	Cedar	GT	KER	21200	59,325
Conectiv Atlantic Generation Inc.	Missouri Avenue	GT	KER	18600	59,349
Reliant Energy Services Inc.	Hunterstown	GT	DFO	19600	59,376
Constellation Power Source	Philadelphia Road	GT	DFO	20700	59,393
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,419
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,445
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,471
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,497
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,523
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,549
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,575
Reliant Energy Services Inc.	Glen Gardner	GT	DFO	19600	59,601
Reliant Energy Services Inc.	Hunterstown	GT	DFO	19600	59,628
Reliant Energy Services Inc.	Hunterstown	GT	DFO	19600	59,655
Reliant Energy Services Inc.	Tolna	GT	DFO	26600	59,682
Reliant Energy Services Inc.	Ortanna	GT	DFO	26600	59,708
Conectiv Atlantic Generation Inc.	Cedar	GT	KER	41900	59,760
Reliant Energy Services Inc.	Shawnee	GT	DFO	19600	59,786
PSEG Fossil LLC	Burlington	GT	KER	18594	59,810
Constellation Power Source	C P Crane	GT	DFO	16000	59,827
Conectiv Delmarva Generation Inc.	West Substation	GT	DFO	20000	59,846
Reliant Energy Services Inc.	Hamilton	GT	DFO	19600	59,872
PSEG Fossil LLC	Sewaren	GT	KER	115200	60,012
Constellation Power Source	Riverside	GT	DFO	25000	60,037
Vineland City of	West Station	GT	DFO	27000	60,069
Reliant Energy Services Inc.	Sayreville	GT	DFO	53133	60,146
Reliant Energy Services Inc.	Sayreville	GT	DFO	53133	60,223
Reliant Energy Services Inc.	Sayreville	GT	DFO	53133	60,296
Reliant Energy Services Inc.	Sayreville	GT	DFO	53133	60,373
PSEG Fossil LLC	Bayonne	GT	KER	21250	60,397
PSEG Fossil LLC	Bayonne	GT	KER	21250	60,421
PSEG Fossil LLC	Kearny	GT	KER	242000	60,617
Constellation Power Source	Herbert A Wagner	GT	DFO	16000	60,634
Reliant Energy Services Inc.	Mountain	GT	DFO	26600	60,661
Reliant Energy Services Inc.	Werner	GT	DFO	53133	60,734
Reliant Energy Services Inc.	Werner	GT	DFO	53133	60,807
Reliant Energy Services Inc.	Werner	GT	DFO	53133	60,880
Reliant Energy Services Inc.	Werner	GT	DFO	53133	60,953
Conectiv Delmarva Generation Inc.	Edge Moor	GT	DFO	12500	60,968
Conectiv Atlantic Generation Inc.	Middle	GT	KER	37200	61,012
Reliant Energy Services Inc.	Gilbert	GT	DFO	23800	61,043
Reliant Energy Services Inc.	Gilbert	GT	DFO	23800	61,074
Reliant Energy Services Inc.	Gilbert	GT	DFO	23800	61,105

Utility	Plant Name	Unit Type	Fuel	Name plate	cumulative MW
Reliant Energy Services Inc.	Gilbert	GT	DFO	23800	61,136
Reliant Energy Services Inc.	Mountain	GT	DFO	26600	61,163
Reliant Energy Services Inc.	Portland	GT	DFO	19600	61,189
PSEG Fossil LLC	Burlington	GT	KER	167400	61,401
PSEG Fossil LLC	National	GT	KER	18594	61,425
PSEG Fossil LLC	Burlington	GT	KER	167400	61,637
Reliant Energy Services Inc.	Portland	GT	DFO	18000	61,656
Reliant Energy Services Inc.	Tolna	GT	DFO	26600	61,683
Reliant Energy Services Inc.	Titus	GT	DFO	17600	61,703
Constellation Power Source	Philadelphia Road	GT	DFO	20700	61,720
Reliant Energy Services Inc.	Titus	GT	DFO	18000	61,739
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,759
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,779
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,799
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,819
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,839
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,859
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,879
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,899
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,919
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,939
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,959
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,979
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	61,999
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	62,019
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	62,039
Potomac Power Resources Inc.	Buzzard Point	GT	DFO	18000	62,059
Conectiv Delmarva Generation Inc.	Madison Street	GT	DFO	11500	62,073
PSEG Fossil LLC	Linden	GT	NG	96000	62,167
PSEG Fossil LLC	Mercer	GT	KER	115200	62,307
PSEG Fossil LLC	Linden	GT	NG	96000	62,401
PSEG Fossil LLC	Linden	GT	NG	18594	62,425
PSEG Fossil LLC	Hudson	GT	KER	115200	62,565

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